UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Regional Transmission Organizations	)	Docket No. RT01-99-000

BUSINESS PLAN
FOR THE DEVELOPMENT AND IMPLEMENTATION
OF A SINGLE REGIONAL TRANSMISSION ORGANIZATION
FOR THE NORTHEASTERN UNITED STATES

Nothing contained in this Business Plan shall be construed as a waiver of any legal or contractual right(s) or authority which any potentially affected party might otherwise have.

Prepared and Submitted by the Participants in the Commission-directed Mediation in this Proceeding

September 10, 2001

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Executive Summary

The Northeastern RTO mediation process commenced on July 24 and concluded on September 7. It was attended by a broad range of stakeholders, including the three Northeastern ISOs, all of the affected transmission owners, the Northeastern state regulatory commissions, marketers and generators that participate in the existing Northeastern markets, major industrial customer interests, many public power entities, electric cooperatives, regional reliability councils, Canadian entities, and representatives of a number of public interest groups. For purposes of the mediation, all of the parties worked in good faith to develop a viable task-oriented business plan for the creation of fully-integrated Northeastern markets, and a single Northeastern RTO to administer those markets and promote the development of new infrastructure. Consistent with the Commission's orders, the PJM design would serve as the platform for the new market and RTO, as modified by best practices from New England and New York.

Although the mediation process was not easy, it succeeded in producing a business plan for implementation of the single northeastern RTO and that specifies clear alternatives in areas of disagreement. As is noted below, the parties reached an early consensus on certain general RTO formation principles and established a non-exclusive list of certain criteria for determining when a proposed best practice should be adopted as a modification to the PJM platform. Greater effort then was devoted to: (i) define the key elements of the PJM platform; (ii) identify differences in the New England and New York models; (iii) note the proposed "best practices" nominated by the respective ISOs; (iv) create implementation milestones and timetables; and (v) incorporate all of the information into "strawman" documents that ultimately became the main sections of the business plan. In addition, the parties devoted considerable effort to developing post-mediation processes to effectively manage the implementation of the business plan. The remainder of this Executive Summary addresses each of these topics in sequence.

I. Consensus RTO Formation Principles

Early in the mediation process, the parties agreed to include the following consensus items into this business plan.

1. One RTO and one energy market for the northeast, with a transition from the current three ISOs and three markets to one RTO with one market.

2. One RTO tariff administered by the RTO for the northeast region.

3. One interconnection process under the decisional control of the RTO that takes into account reliability and operating concerns.

4. An RTO must have the ultimate responsibility for both transmission planning and expansion within its region that will enable it to provide efficient, reliable and non-discriminatory service and coordinate such efforts with the appropriate state authorities.

5. The RTO must allow market participants to self-supply their ancillary services to the extent possible.

6. The RTO must have operational authority for all transmission facilities under its control.

7. Our common goal is to establish one northeast RTO based upon "best practices" using PJM as a platform.

8. Our common goal is to implement the northeast RTO as soon as practical while maintaining the reliability of the power system and the efficiency and integrity of existing markets during the transition.

10. There shall be one organizational structure for the northeast RTO

11. Appropriate market-driven and emergency-based demand response programs shall be incorporated into the RTO markets.

12. In transitioning to a single RTO, the principles of revenue neutrality as articulated in the Commission's orders will be preserved.

13. Stakeholders must have the opportunity for meaningful and timely input into the RTO's decision-making process.

14. The costs of implementing and operating a single northeast RTO should be borne on an equitable basis by all market participants.

II. Criteria for Determining Best Practices

The parties also arrived at a consensus that the determination of "best practices" is a decision reached in a process involving all stakeholders and participants which identifies those mechanisms which may supplement or supplant portions of the PJM platform consistent with the Commission's Northeastern RTO orders. No predetermined criteria shall exclude the consideration of a best practice mechanism. However, core considerations in evaluating best practices should include:

- Economic efficiency and competitive considerations
- Costs of implementation/Benefits and effectiveness
- Impact on market participants and ratepayers
- Impact on reliability
- Time to implement
- Extent of integration with other regions
- Risks, including risk of failure
- Impacts on existing or alternative technologies

This list of considerations is not exclusive and does not imply a ranking or order of priority for these items.

III. Overview of the Business Plan

This proposed business plan consists of eight sections. Section One, as discussed below, addresses the process that follows this mediation. The next seven sections describe the tasks that must be completed to establish a single Northeastern RTO and market. These seven sections evolved from the weekly "strawman" documents that were prepared over the course of the first five weeks of the mediation process. Each section focuses on a major RTO formation issue that must be resolved for the new market and RTO. Section Two addresses governance, independent transmission companies, market monitoring and mitigation, financing, cost recovery, and information release. Section Three focuses on market design, Section Four pertains to operations, Section Five deals with technology assessment issues, Section Six covers transmission tariff-related matters, Section Seven describes regional transmission planning, and Section Eight addresses inter-regional coordination.

Each section recognizes that the Northeastern RTO business plan starts with the PJM platform and therefore begins by describing the relevant aspects of the PJM platform in some detail. Where there are differences in the approaches taken by ISO-NE[1] or the NYISO they are noted for potential consideration as best practices. Any differences that an individual ISO has nominated as the "best practice" in a particular area is designated with a boldface "BP."[2] The Business Plan also includes a description of the Northeast Independent Transmission Company, L.L.C. proposed in Docket No. RT01-86-000, to assist the parties' consideration during the post-mediation process of an ITC or ITCs designed along such lines as part of a hybrid RTO.

Each section also describes specific RTO and market implementation tasks and establishes clear milestones for accomplishing them. In addition, the business plan includes a separate appendix for each section (Appendices A-1 through A-7) that lists the stakeholder-identified issues that pertain to the corresponding section's subject matter. The identified issues raise questions of relevance to all aspects of RTO formation and will be considered at the appropriate stage during the RTO formation process.

The milestones for the RTO and market implementation tasks represent agreed upon deadlines that the parties generally believe are realistically achievable, but in some important areas there is disagreement and milestone alternatives are presented. The parties also generally agree that it may be possible to complete various tasks earlier than the date targeted by the relevant milestones and will strive to do so whenever possible. It is envisioned that the parties will work concurrently to reach the milestones described in each section of the business plan to the greatest extent possible. The overall timelines are depicted on the following pages.

Each section includes a more detailed timeline identifying more specific tasks, sub-tasks and milestones. There is consensus on some of these details. For example, it is agreed that the necessary RTO technology assessment can be complete no later than seven months after the estimated November 1 issuance date of a Commission order approving the business plan, *i.e.*, by the second quarter of 2002. It

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1 With respect to market design, the differences noted for ISO-NE are based on elements of the "Standard Market Design" that ISO-NE and the New England Power Pool Participants Committee have proposed be developed for New England.

2 In the description of the platform and differences, elements that are proposed, approved, or ordered, but not yet effective, are shown in brackets.

is also generally agreed that a regional transmission planning system can be developed by the fourth quarter of 2002, and that tariff-related issues can be resolved by the second quarter of 2003.

The key area of difference, which will drive the overall completion date, is the amount of time required to complete the design and implementation of a Northeastern energy market based on the PJM platform as modified to accommodate best practices. During the mediation, the parties developed three alternative timetables for market design and implementation.

Option 1-M provides that market design could be implemented in the fourth quarter of 2004, subject to extension if additional complexity is introduced or new design requirements become apparent. Option 1-M calls for the new Transition Board to be established and to develop an appropriate implementation plan (including coordination with existing ISOs) prior to systems and market implementation. It also anticipates that RTO market rules, tariffs, operating criteria, business processes, implementation teams and functional requirements will be completed during the initial 12-month period, before launching into the 24-month systems and market implementation phases.

As set forth in Appendix B to the Business Plan, the supporters of Option 1-M believe that it should be adopted for implementation of a single market for the Northeast because it embodies best practice implementation methodologies, including effective risk management. The supporters believe that the creation of the Northeast market, which will be the largest electricity market in the world, should be implemented through Option 1-M's "management executes an approved plan" approach. Option 1-M's implementation approach, in the supporters' view, constitutes a realistic, achievable plan for prompt implementation of a robust single market incorporating best market practices. The supporters believe that Option 1-M ensures an orderly transition from the three existing markets, recognizing the existing responsibilities and resource limitations of the existing ISOs, and the need for a Transition Board to be in place at the outset. In the supporters' view, Option 1-M meaningfully accommodates the seven-month technology assessment included in the Business Plan. Option 1-M is consistent, in the view of its supporters, with the Commission's orders and the Consensus Principles that the market design be based on the PJM platform <u>and</u> incorporate best practices from other ISO markets. In the NYISO's view, these best practices include ancillary service and demand response programs, co-optimization of energy and ancillary services markets, precise automated control over generators, New York City mitigation measures and local reliability rules.[3] The supporters believe that, in doing so, Option 1-M appropriately balances the desire of a significant number of market participants to implement a single electricity market as soon as possible (i.e., the 24-month period for systems and market implementation does not vary significantly among the three options)[4] with the risk management required to successfully implement this complex project. Finally, in the supporters' view, Option 1-M supports the Commission's open-architecture requirements, including the possible formation of ITCs.

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[3] The New York ISO believes that if certain crucial best market practices are not included in the Northeast RTO market design at the commencement of a single market then New York consumers will incur substantial new costs and New York State will be exposed to new reliability problems.

[4] The New York ISO believes that it will also be possible to identify elements of a single market (with the exception of a single energy market) that can be implemented on an interim basis and to implement them in parallel with the move to a single market. The NYISO anticipates that this task would run in parallel with, and not delay, the development of an end-state market and envisions that it would be complete by December 1, 2002.

The supporters of Option 1-M are listed in Section Three of this Business Plan following the Option 1-M milestones.

Under Option 2-M, the "Integrated Northeast Market Concept" proposed by the New York transmission owners and others, certain market design components (not including the single energy market) would be operational beginning in the fourth quarter of 2002 with full implementation of the single Northeast market by the third quarter of 2004. Option 2-M includes a seven-month upfront technology and best practice assessment conducted at the outset of the process immediately followed by a phased implementation plan.

As set forth in Appendix C, the supporters of Option 2-M believe that the Integrated Northeast Market Concept expeditiously establishes a common market design while ensuring reasoned adoption of best practices to assure reliability and market efficiency. Option 2-M proposes that the "Technology/Best Practice" assessment process will be conducted by an independent Board with meaningful stakeholder input in order to evaluate technology and best practices prior to the commencement of a phased implementation plan. The supporters of Option 2-M anticipate activation of the first common market features within 12 months of the Commission's Order. Full operation of the integrated RTO markets would be completed by the third quarter of 2004. While the Option 2-M process is assumed to start on November 1, 2001, the New York transmission owners prefer that the process commence immediately after the 45-day mediation process in order to accelerate the business plan implementation. The supporters of Option 2-M are listed in Section Three of this Business Plan, following the Option 2-M milestones.

Option 3-M, developed by PJM, envisions that the single energy market would be implemented by the fourth quarter of 2003. This option anticipates that systems implementation and market trials would require 24 months, but that systems implementation would commence on November 1, 2001, based on acceptance at the outset of a basic framework known as the "Regional Networked Market Concept."

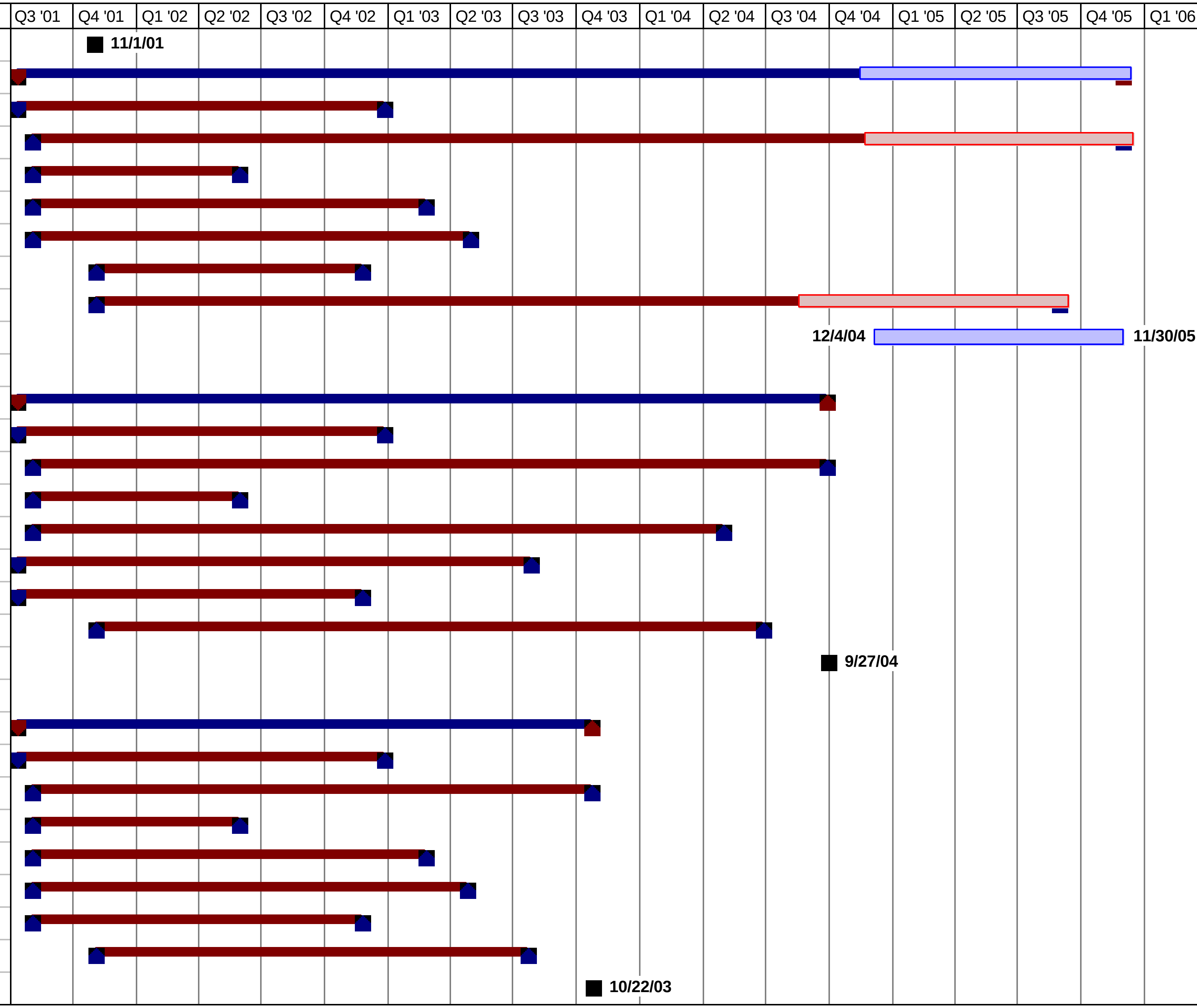
As explained by PJM in Appendix D, the Regional Networked Market Concept is predicated on the extension of the PJM platform across the entire Northeast, but retention of existing local control centers and existing energy management systems in the three areas to address local reliability issues and act as data servers to the regional market system. The supporters of Option 3-M believe that it also addresses the local reliability best practices identified by NYISO and ISO-NE and allows three months during the post-mediation process to determine which additional best practices identified in this business plan should be adopted to supplement the accepted basic framework. They believe that most of the identified best practices can be incorporated at market start-up without affecting the anticipated implementation date, if adopted in the first three months. They envision that a few of the suggested best practices could not be implemented by the fourth quarter of 2003, but could be implemented after initial market start-up, if desired, by the fourth quarter of 2004. The supporters of Option 3-M believe that it presents an opportunity to implement a single northeastern market at the earliest possible date in a manner that fully addresses all essential concerns, including the reliability and other concerns that have been raised, and that allows incorporation of many significant best practices at the outset and other best practices over time. The parties supporting Option 3-M are listed in Section Three of this Business Plan, following the Option 3-M milestones.

Absent a settlement on this issue, the Commission will have to make its own assessment of the competing policy considerations and decide upon an appropriate implementation timetable.

The following charts depict the tasks and milestones reflected in the various options.

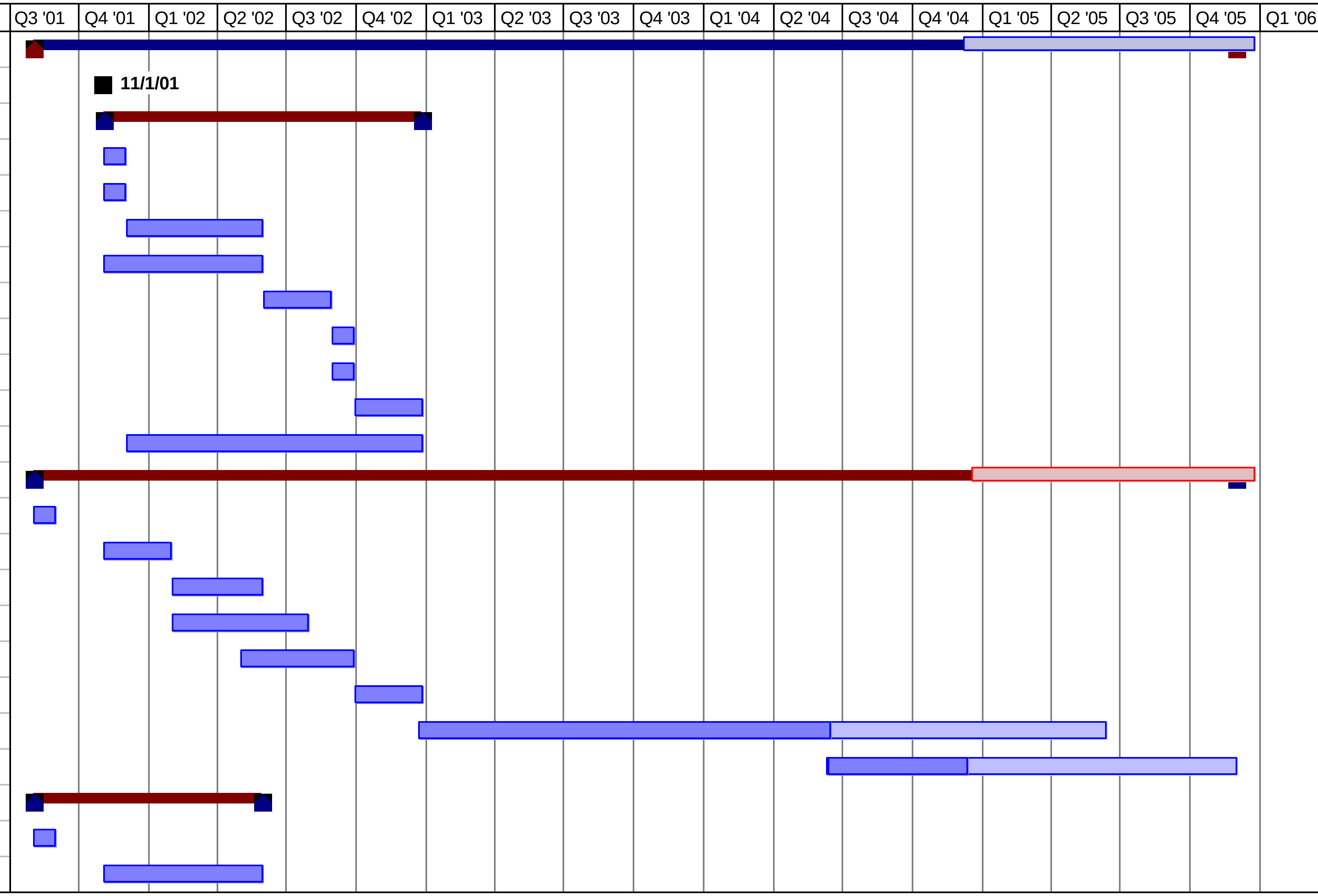
Northeast RTO Milestones (Summary of Options 1-M, 2-M, and 3-M)

ID	Task Name
1	**Commission Issues Order on ALJ's Report**
2	**Northeast RTO Option 1-M**
3	Governance
13	Market Design
22	Technology Assessment
25	Operations
32	Transmission Tariff
42	Transmission Planning and Interconnection
47	Interregional Coordination
50	Completion - Range
51	
52	**Northeast RTO Option 2-M**
53	Governance
63	Market Design
77	Technology Assessment
80	Operations
87	Transmission Tariff
97	Transmission Planning and Interconnection
102	Interregional Coordination
105	Completion
106	
107	**Northeast RTO Option 3-M**
108	Governance
118	Market Design
126	Technology Assessment
129	Operations
136	Transmission Tariff
146	Transmission Planning and Interconnection
152	Interregional Coordination
155	Completion



Northeast RTO Milestones (Option 1-M)

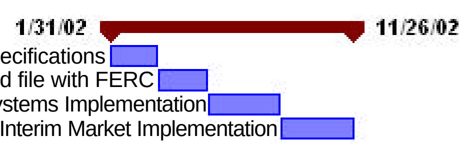
ID	Task Name
0	**Northeast RTO**
1	**Commission Issues Order on ALJ's Report**
2	**Governance**
3	Establish Initial Governance and Stakeholder Structures
4	Commence Implementation
5	Determine Basic Organizational Framework
6	Determine Status of Market Monitor
7	Develop RTO Agreements
8	Develop Transition Plan
9	FERC Filing
10	FERC Approval
11	Complete Implementation
12	**Market Design**
13	Describe Platform and Differences
14	Produce RTO Market Design for Northeast (Note 1.)
15	Produce Detailed Market Specifications
16	Develop Implementation Plan
17	Finalize Tariff and File with the FERC
18	FERC Approval of Tariff
19	Systems Implementation
20	Market Implementation
21	**Technology Assessment**
22	Define Parameters
23	Technology Assessment



Note (1.) NY ISO proposes an additional task, as follows:

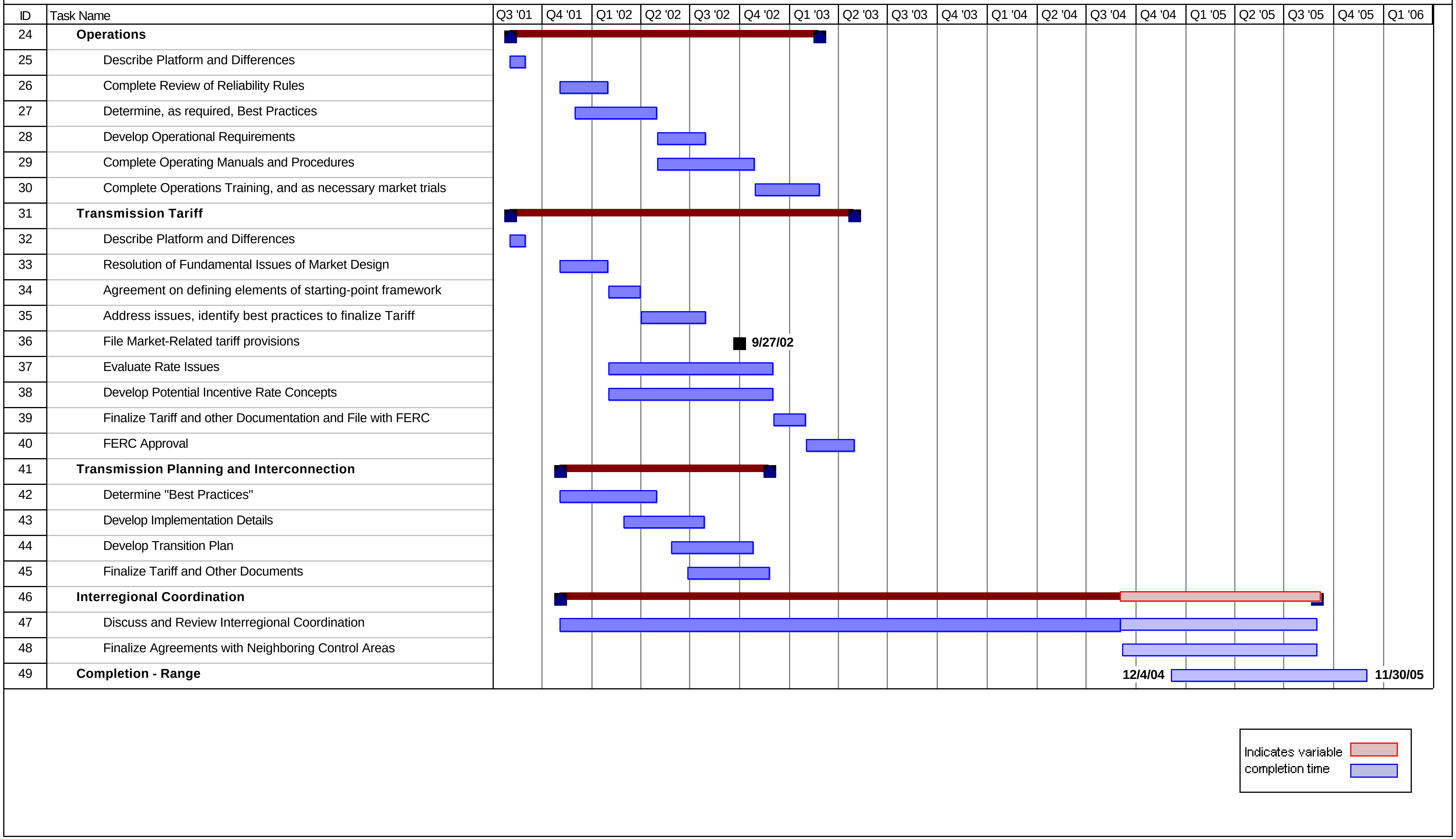
Interim steps towards a Common Market

Develop detailed interim specifications
Finalize tariff and file with FERC
Interim Systems Implementation
Interim Market Implementation



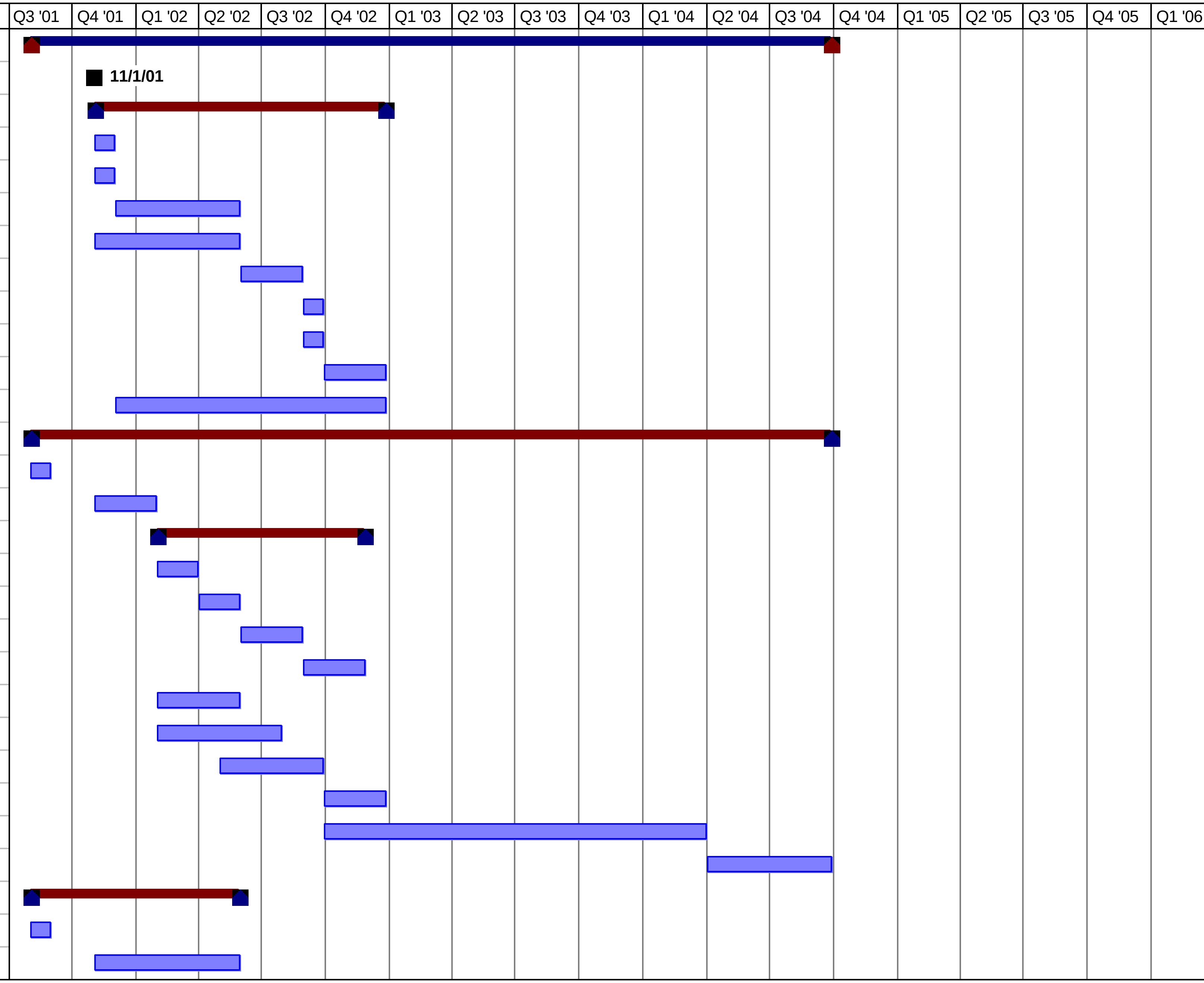
Indicates variable completion time

Northeast RTO Milestones (Option 1-M)



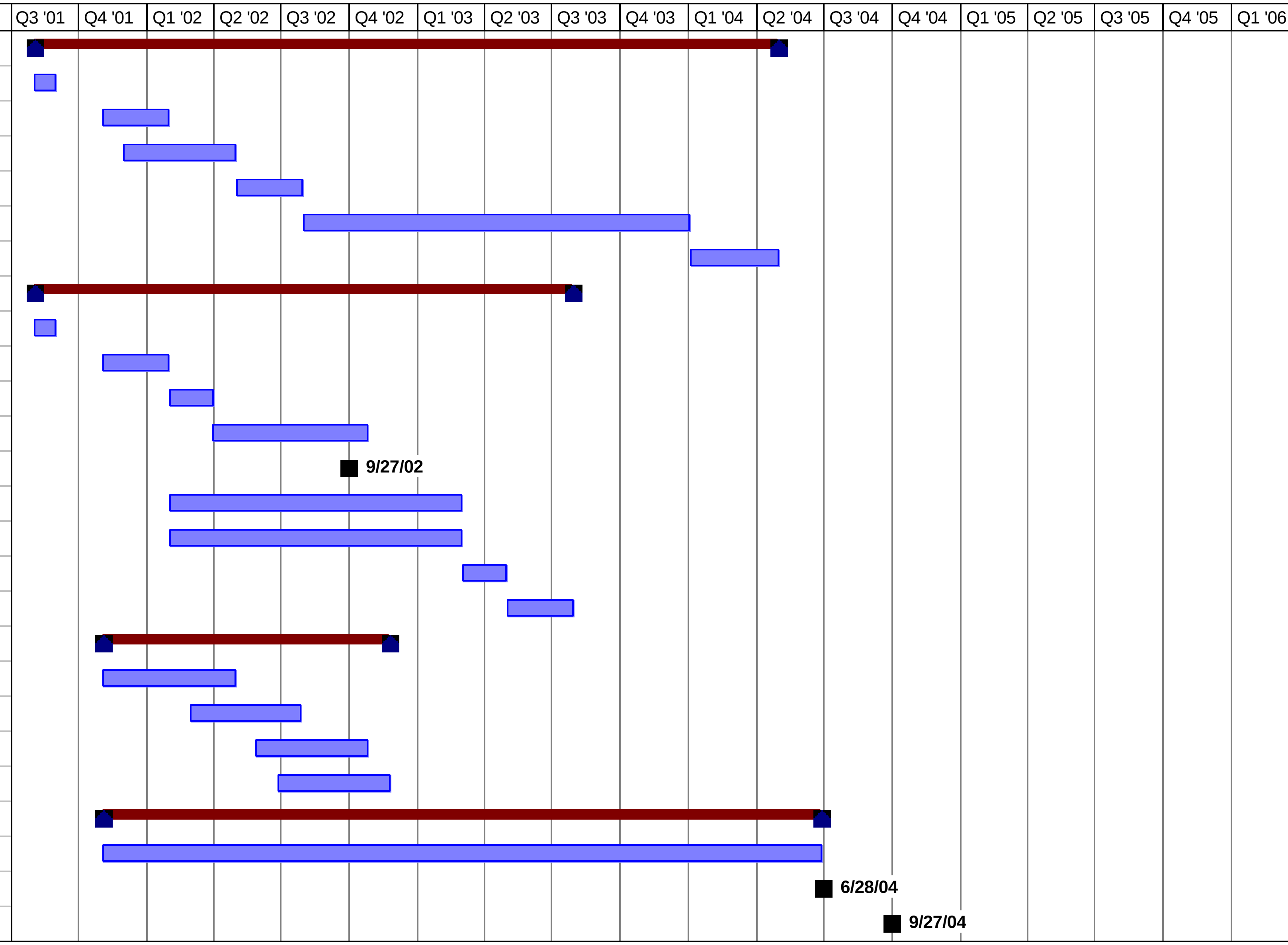
Northeast RTO Milestones (Option 2-M)

ID	Task Name
0	**Northeast RTO**
1	**Commission Issues Order on ALJ's Report**
2	**Governance**
3	Establish Initial Governance and Stakeholder Structures
4	Commence Implementation
5	Determine Basic Organizational Framework
6	Determine Status of Market Monitor
7	Develop RTO Agreements
8	Develop Transition Plan
9	FERC Filing
10	FERC Approval
11	Complete Implementation
12	**Market Design**
13	Describe Platform and Differences
14	Produce RTO Market Design for Northeast
15	**Identify Interim Steps for Moving to a Common Market**
16	Developed detailed interim specifications
17	Finalize interim tariff and file with FERC
18	Interim systems implementation
19	Interim Market Implementaiton
20	Produce Detailed Market Specifications
21	Develop Implementation Plan
22	Finalize Tariff and File with the FERC
23	FERC Approval of Tariff
24	Systems Implementation
25	Market Implementation
26	**Technology Assessment**
27	Define Parameters
28	Technology Assessment



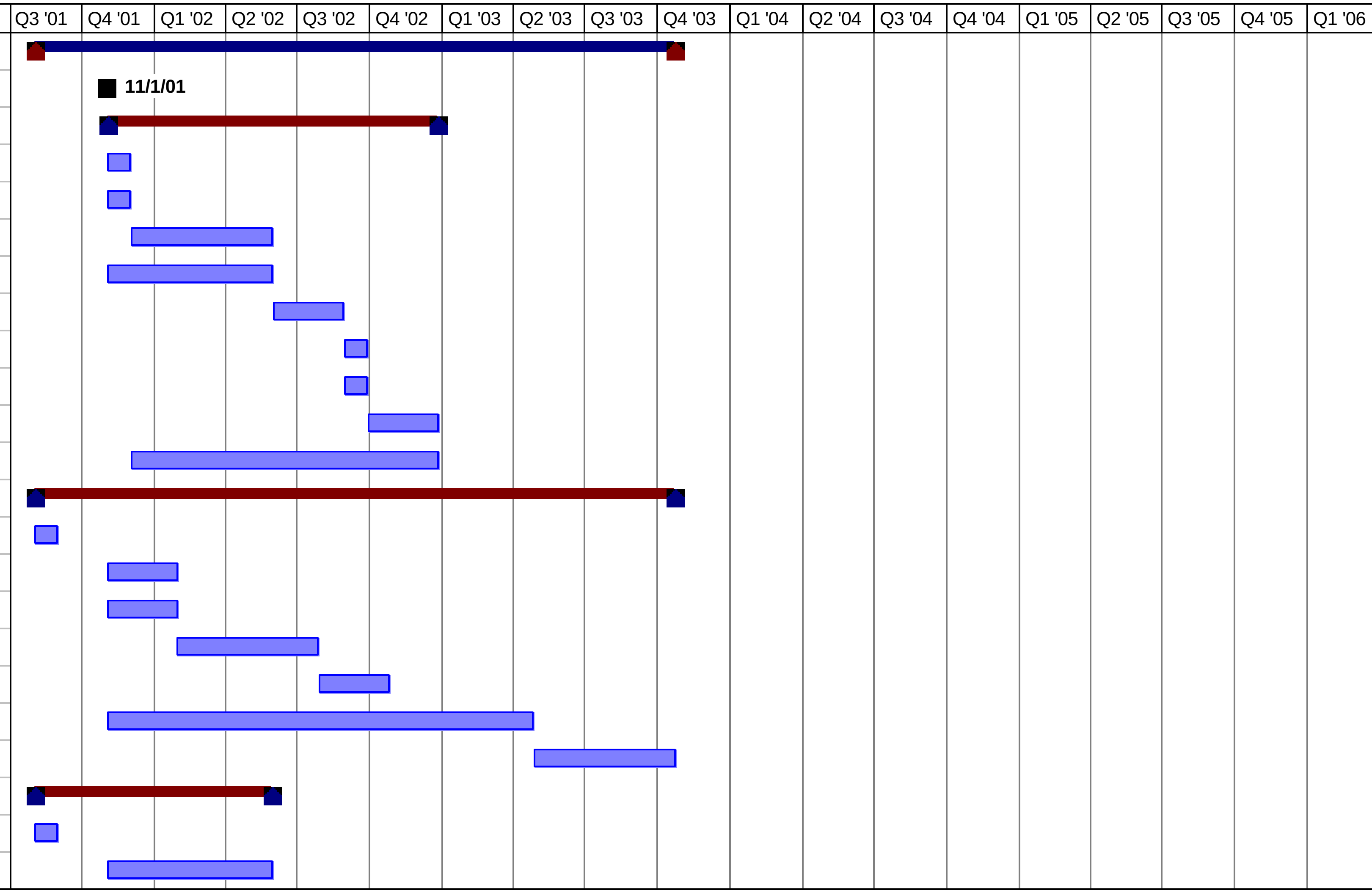
Northeast RTO Milestones (Option 2-M)

ID	Task Name
29	**Operations**
30	Describe Platform and Differences
31	Complete Review of Reliability Rules
32	Determine, as required, Best Practices
33	Develop Operational Requirements
34	Complete Operating Manuals and Procedures
35	Complete Operations Training, and as necessary market trials
36	**Transmission Tariff**
37	Describe Platform and Differences
38	Resolution of Fundamental Issues of Market Design
39	Agreement on defining elements of starting-point framework
40	Address issues, identify best practices to finalize Tariff
41	File Market-Related Tariff Provisions
42	Evaluate Rate Issues
43	Develop Potential Incentive Rate Concepts
44	Finalize Tariff and other Documentation and File with FERC
45	FERC Approval
46	**Transmission Planning and Interconnection**
47	Determine "Best Practices"
48	Develop Implementation Details
49	Develop Transition Plan
50	Finalize Tariff and Other Documents
51	**Interregional Coordination**
52	Discuss and Review Interregional Coordination
53	Finalize Agreements with Neighboring Control Areas
54	**Completion**



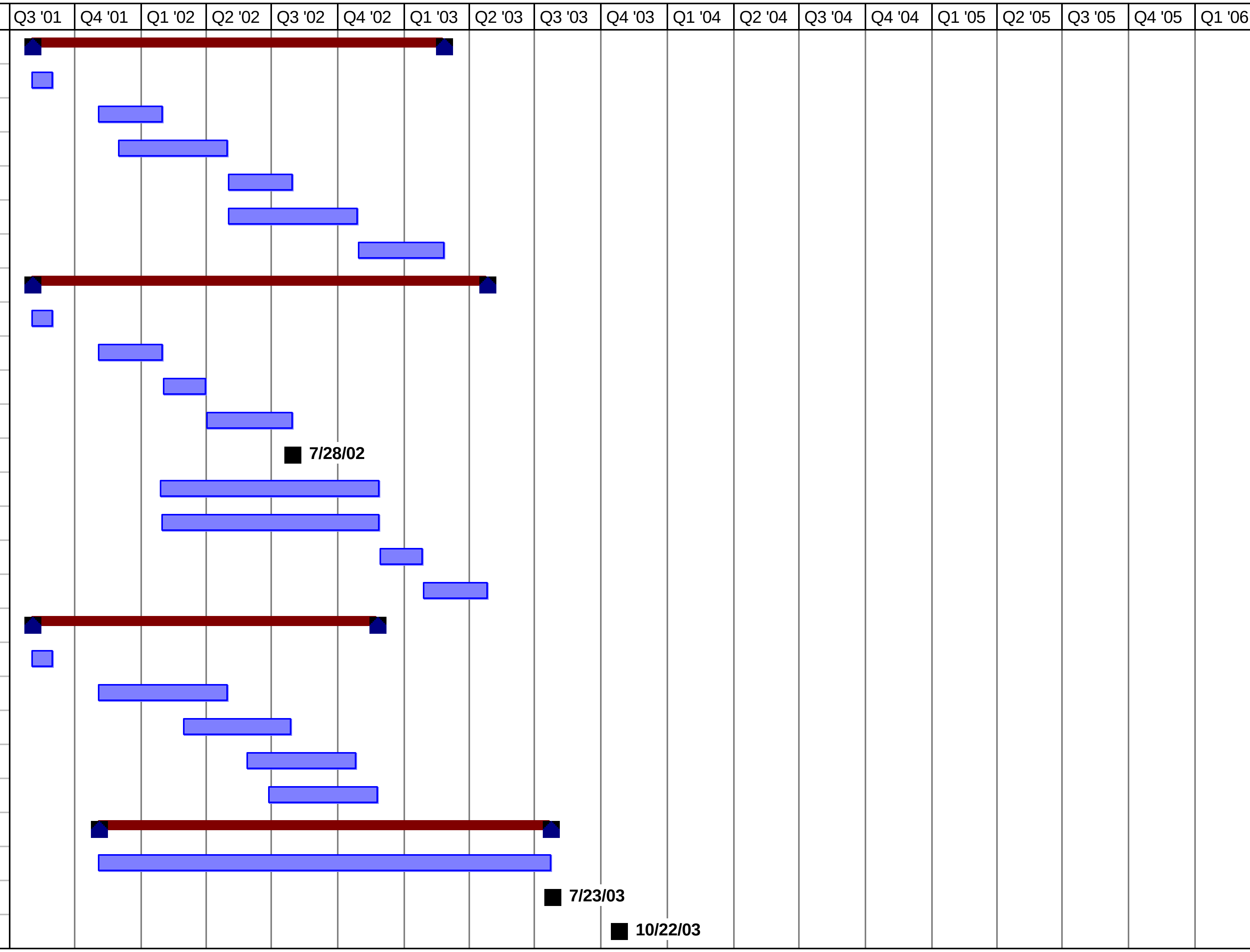
Northeast RTO Milestones (Option 3-M)

ID	Task Name
0	**Northeast RTO**
1	**Commission Issues Order on ALJ's Report**
2	**Governance**
3	Establish Initial Governance and Stakeholder Structures
4	Commence Implementation
5	Determine Basic Organizational Framework
6	Determine Status of Market Monitor
7	Develop RTO Agreements
8	Develop Transition Plan
9	FERC Filing
10	FERC Approval
11	Complete Implementation
12	**Market Design**
13	Describe Platform and Differences
14	Supplement PJM Platform with BPs
15	Develop Implementation Plan
16	Finalize Tariff and File with the FERC
17	FERC Approval of Tariff
18	Systems Implementation
19	Market Implementation
20	**Technology Assessment**
21	Define Parameters
22	Technology Assessment



Northeast RTO Milestones (Option 3-M)

ID	Task Name
23	**Operations**
24	Describe Platform and Differences
25	Complete Review of Reliability Rules
26	Determine, as required, Best Practices
27	Develop Operational Requirements
28	Complete Operating Manuals and Procedures
29	Complete Operations Training and, as Necessary, Market Trials
30	**Transmission Tariff**
31	Describe Platform and Differences
32	Resolution of Fundamental Issues of Market Design
33	Agreement on defining elements of starting-point framework
34	Address issues, identify best practices to finalize Tariff
35	File Market-Related tariff provisions
36	Evaluate Rate Issues
37	Develop Potential Incentive Rate Concepts
38	Finalize Tariff and other Documentation and File with FERC
39	FERC Approval
40	**Transmission Planning and Interconnection**
41	Describe Platform and Differences
42	Determine "Best Practices"
43	Develop Implementation Details
44	Develop Transition Plan
45	Finalize Tariff and Other Documents
46	**Interregional Coordination**
47	Discuss and Review Interregional Coordination
48	Finalize Agreements with Neighboring Control Areas
49	**Completion**



IV. Post-Mediation Process

The mediation participants also developed three alternative approaches to the post-mediation process. The three options are similar in many respects but have a few fundamental differences. As outlined in detail in the following section, all three options envision that a new company, with a new board, would be established after the Commission's order on the mediation report. That board would manage the going-forward process, including implementation of the Business Plan, during the transition to a new RTO for the Northeast, with the advice and input of a new advisory stakeholder committee.

The post-mediation process proposals differ primarily as to the composition of that board and the degree to which the permanent governance issues are resolved by the Business Plan now rather than over the course of the next year. The mediation participants also have differing views on which entities should have the right to submit filings under §205 of the Federal Power Act.

The first option, Option 1-G, does not specifically address the make-up of the Board within its defined terms. It is supported by one group of participants who propose that the Board consist of 5 representatives from the PJM Board, 3 representatives from the NYISO Board, and 2 representatives from the ISO-NE Board, with a CEO that would be an 11th voting member of the Board. It is also supported by another group of participants who believe that the Board should be composed of an equal number of representatives from each ISO Board. In each case, the new Board would nominate the Board members for a permanent Board at the end of the transition, which then would be elected by the stakeholders. Option 1-G provides that during the transition the new board will not have the right to submit filings under FPA §205 unless agreed by the parties holding such rights.

The second option, Option 2-G, specifies an RTO Transition Board comprised of 3 members from each ISO Board and an additional 4 members elected by the stakeholders. Directors of existing ISO Boards may serve in a similar capacity on the RTO Transition Board but the existing ISOs' CEOs and the Chairmen of their respective Boards would have to resign their positions before becoming the CEO or Chairman of the RTO. The CEO would be non-voting. Option 2-G leaves all decisions regarding the composition of the permanent board to subsequent determination in the going-forward process by the Transition Board and the stakeholders. Option 2-G provides that the Transition Board will not have the right to submit filings under §205. Some supporters of Option 2-G believe that stakeholders should have §205 filing rights and some believe that the Transition Board should have §205 filing rights.

The third option, Option 3-G, specifies a Board comprised of 5 representatives from the PJM Board, 3 representatives from the NYISO Board, and 2 representatives from the ISO-NE Board, with a CEO that would be an 11th voting member of the Board. Under this option, this Board would serve as a permanent Board managing both the transition process and the new RTO after the transition. Option 3-G provides that this board should have the right to submit §205 filings during the transition, as well as thereafter.

During the mediation process, the parties conducted a ballot on their preferences with regard to the composition of the new board. The results are tallied in Appendix E.

Finally, all of the post-mediation process alternatives include an advisory stakeholder process. Section One contains the straw proposal on stakeholder process (incorporating options on several issues) developed by the mediation participants.

SECTION ONE

Post-Mediation Process

The participants in the mediation developed three options for the post-mediation process and an associated straw proposal on the stakeholder process (including options on several issues). These are set forth in this section.

Option 1-G

PJM/New England Transmission Owners/One RTO Coalition[5]

Proposal on Post-Mediation Governance

1. Establishment

a. Immediately after the issuance of a FERC order in this proceeding, a new limited liability company or other limited liability entity operating on a revenue-neutral basis, with a new independent Board, should be established. Board members must satisfy the independence requirements set forth in Order No. 888. The Board should address any conflict of interest issues that may arise.

b. This Board will manage the going-forward process during the transition to a new RTO for the Northeast.

c. The newly formed company, at the end of the transition, would become the new RTO (or part of a new hybrid RTO along with one or more ITCs) for the Northeast.

d. The corporate structure selected for the new RTO shall be subject to: (i) ensuring the Board and the RTO are independent from the market participants; and (ii) satisfactory resolution of issues related to existing tax-exempt financing of certain participants and other issues related to public, cooperative, and governmental entities.

2. The New Board

a. Transition Board

(1) The Transition Board's directors initially should be chosen by, and from, the Boards of the existing ISOs. This will ensure continuity and that the new Board has experience with the reliability and market issues facing the Northeast. This proposal does not address the number of directors to be selected by, and from, the Board of each ISO.

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5 This proposal is supported by PJM, ISO New England, the New England Transmission Owners, the One RTO Coalition (which includes generators, marketers, and transmission owners, possessing at least 95,000 MW of generation in the Northeast and including half of the top 25 power marketers in the country), and others. A complete list of supporters follows the description of Option 1-G.

(2) Directors of the existing ISOs may be permitted to serve as Directors on the Transition Board without resigning their current positions. This will ensure maximum coordination and cooperation among the ISOs during the transition.

(3) The Transition Board would serve during the transition to one RTO for the Northeast.

(4) The Transition Board's fiduciary duties must be to implement the business plan consistent with maintaining for the public a safe, environmentally responsible, and reliable electric system, creating and maintaining a robust, competitive, nondiscriminatory marketplace. These duties shall include, but not be limited to, preserving local and control area reliability, overall market efficiency, and the effectiveness of market power mitigation measures. The Board further must ensure that no constituency or constituencies have any undue influence.

b. Permanent Board

(1) Towards the end of the transition and as FERC is considering the transition results, the Transition Board would nominate 10 or 13 members, depending upon the consideration discussed below, to serve as the Permanent Board, and the new stakeholder committee would vote to elect the slate. Transition Board members may be selected for the Permanent Board.

(2) During the transition, and as soon as practicable, the Transition Board shall, with stakeholder consultation and advice, establish an independent monitor to monitor the RTO markets and evaluate and audit all components and activities of the RTO insofar as these components and activities affect the RTO markets.

(3) If it is decided, during the course of implementing the business plan, that the market monitoring function should report to the RTO, rather than be a separate, independent component of the RTO, the purpose of the additional 3 board members is to augment the board to include a 3-member subcommittee that will serve as the market monitoring committee of the Board, to which the chief market monitoring officer would report. These 3 board members would not be permitted to serve on any other board subcommittees. (If the market monitoring plan of the new RTO is approved earlier and subject to the consideration discussed above, then these 3 board members could be selected ahead of the rest of the Permanent Board in order that they can begin familiarizing themselves with the new markets before they commence, and the Transition Board shall endeavor to implement a market monitoring function at the earliest practicable time in the transition.)

(4) The 13 members of the Permanent Board would have 5-year staggered terms.

(5) The new Board's fiduciary duties must be to maintain for the public a safe, environmentally responsible, and reliable electric system and create and maintain a robust, competitive, nondiscriminatory marketplace. The Board further must ensure that no constituency or constituencies have any undue influence.

3. The New Transition Board's Responsibilities

a. The new Transition Board's responsibility should be to carry out the RTO Business Plan in conjunction with advice and input from stakeholders, but the Transition Board shall not be empowered to submit filings under Section 205 of the Federal Power Act without the consent or authorization of the party or parties that have the right to make such filings. The Transition Board shall have the authority to submit filings under section 206 of the Federal Power Act. If disputes arise between stakeholders and the Transition

Board, they may be submitted to dispute resolution (described below) and, if necessary, to FERC.

b. The Transition Board, in conjunction with stakeholders, initially will concentrate on the design and planning of a single market for the Northeast and related issues, and it will attempt to resolve these issues expeditiously during the first three months.

c. There shall be no prejudgment one way or the other regarding whether one or more ITCs or similar organizations will or will not be part of the RTO design for the Northeast. As described herein, it may be determined that initially there will be one or more ITCs or similar organizations, or it may be determined that initially there will not be any ITCs or similar organizations.

d. The Transition Board shall not prejudice the organizational structure or governance of the RTO, except that the Permanent Board shall constitute the initial Board of the organization within the RTO fulfilling ISO functions, including, but not necessarily limited to, market and related operational responsibilities.

e. As early as possible, the Transition Board, through its staff, will enter into negotiations with proponents of one or more ITCs or similar organizations and with other Transmission Owners regarding the potential divisions of RTO responsibilities among the ITC(s) or similar organizations that may form, other Transmission Owners, and the ISO within the RTO. The Board's staff will keep all stakeholders fully informed at all times about these negotiations through the advisory stakeholder process that is established, and it will solicit and consider stakeholder advice and input regarding the subject matter of these negotiations. If these negotiations do not produce an agreement regarding potential divisions of functions, then, a dispute may be submitted to dispute resolution (described below) and, if necessary, to FERC.

f. Except with respect to its decisions regarding its positions in the above-described negotiations, and except as stated in paragraphs (g) and (h), the Transition Board shall not be responsible for determining the organizational structure and governance of the RTO insofar as they relate to whether or not the RTO will have a hybrid organizational structure and, if so, its nature, or the formation of potential ITC(s) or similar entities or for implementing those portions of the RTO Business Plan that relate solely to the responsibilities assigned to ITC(s), if any. The RTO responsibilities ultimately shall be managed in accordance with the outcome of the negotiations, if any, between the Transition Board and the proponents of ITC(s) or other similar entities and other Transmission Owners, or by the outcome of any dispute resolution, or by the Transition Board's developed transmission design (described below), all subject to approval of the Commission.

g. At all times, the Transition Board shall exercise decisional responsibility for market-related transmission rules, as necessary for the design, planning, and implementation of a single market.

h. The Transition Board, as necessary, may design fully integrated transmission-related tariff and other matters on a parallel track with the foregoing, that would accommodate the initial implementation of the new RTO without ITCs (or similar entities), if they do not form prior to such initial implementation. However, the Transition Board shall not present proposals for this alternative for discussion among stakeholders during the first 7 months after the Commission order on the Judge's mediation report.

i. Consistent with an open architecture, nothing shall prevent the formation of ITC(s) or similar entities after initial formation of the single RTO for the Northeast.

j. The CEOs of the existing ISOs shall facilitate the transition of the existing ISO functions into the ultimate RTO structure as established by the Transition Board by developing a reasonable transition plan.

4. Chief Executive Officer and Initial Staffing

a. The Transition Board should select and appoint a CEO.
b. The existing ISOs' CEOs should be eligible for this position.[6]
c. The CEO should be a voting member of the Transition Board.
d. Staffing would be drawn initially from the existing ISO staffs.

5. Transitional Stakeholder Process and Dispute Resolution

a. A new, advisory stakeholder committee process shall be established to advise the Transition Board and to address all issues in the RTO Business Plan. The Transition Board will consider the views expressed by the majority of stakeholders, as well as minority views, on any material issue.
b. The stakeholder advisory process generally should utilize the two-tier governance model of ISOs, with voting protocols that prevent dominance by any group of stakeholders.
c. There also should be a liaison arrangement between the Board and the state regulatory commissions, through which the state commissions can provide advice to the Board.
d. The Board shall advise the stakeholders of its decisions on matters during the transition, including, when appropriate, written statements of the reasons for such decisions. When the Board makes a FERC filing that is contrary to the formally expressed advice of the stakeholder committee, it shall explain in the FERC filing its reasons for doing so.
e. If a dispute arises between stakeholders, on the one hand, and the new Transition Board, on the other hand, any party may submit the dispute to the FERC Dispute Resolution Service for expedited non-binding dispute resolution. A Third Party Neutral assigned by the Dispute Resolution Service will be appointed promptly, on a stand-by basis, to mediate each dispute for a period of one week (unless extended by agreement of all parties, including the Board, to the dispute).
f. If agreement is not reached through the assistance of the Dispute Resolution Service, the Third Party Neutral shall submit the dispute, along with a report of the mediation, to the FERC for resolution. The parties simultaneously shall submit briefs within 10 days. The FERC shall attempt to resolve the dispute within 20 days thereafter.
g. The parties to any dispute may waive the above-described mediation step and proceed directly to FERC for resolution of a dispute.
h. The rights of any party under the FPA are preserved. In particular, while a FERC ruling on a dispute submitted to it shall resolve the issue for purposes of implementing the business plan, it shall not alter or restrict such rights.

6. Existing ISO Boards

a. Existing ISO Boards should continue with their present duties during the transition period, which should be as short as possible.

7. Funding

a. The existing ISOs should fund the new Board's activities pending the implementation of a FERC-approved self-funding mechanism.

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[6] ISO-NE believes that the CEO appointed by the Transition Board must agree to serve on a full-time basis.

SUPPORTERS OF OPTION 1-G

ISOs/Control Areas

Allegheny Power System Operating Companies (PJM West)
ISO New England Inc.
PJM Interconnection, L.L.C.

New England Transmission Owners

Bangor Hydro-Electric Company
Central Maine Power Company
Central Vermont Public Service Corporation
National Grid USA
NU Operating Companies
NSTAR Services Company
The United Illuminating Company
Vermont Electric Power Company

The One RTO Coalition

AES NewEnergy
AES New York LLC
American National Power
Aquila Inc.
Atlantic City Electric Company
Baltimore Gas & Electric
Calpine
Commonwealth Chesapeake Company, LLC
Constellation Energy Group
Constellation Power Source
Delmarva Power & Light Company
Dominion Energy
Duke Energy North America
Edison Mission Energy
Edison Mission Marketing & Trading
El Paso Merchant Energy, L.P.
Energy Management, Inc.
Enron Power Marketing, Inc.
Entergy Nuclear Northeast
Exelon Generation Company, LLC
FPL Energy
HQ Energy Services (U.S.) Inc.
Keyspan-Ravenswood, Inc.
Mirant Americas, Inc.
Mirant Americas Energy Marketing, LP
Morgan Stanley Capital Group Inc.
NEPOOL Industrial Customer Coalition
The NRG Companies
Old Dominion Electric Cooperative

Orion Power
PECO Energy Company
PG&E National Energy Group
PJM Industrial Customer Coalition
Potomac Electric Power Company
PPL EnergyPlus, LLC
PPL Electric Utilities Corporation
PSEG Power, LLC
PSEG Energy Resources & Trade, LLC
Public Service Electric & Gas Company
Reliant Energy Northeast Generation, Inc.
Select Energy Inc.
Sithe New England Holdings LLC
Sithe Power Marketing LP
TransEnergie U.S., Ltd.
TXU Energy Trading
UGI Utilities, Inc.
The Williams Companies, Inc.
Wisvest-Connecticut, LLC

Additional Supporters

Allegheny Electric Cooperative, Inc.
American Wind Energy Association
District of Columbia Public Service Commission
Jersey Central Power & Light Company
Maryland Public Service Commission
Massachusetts Public Interest Research Group
Massachusetts Energy Consumers Alliance
Metropolitan Edison Company
Mid-Atlantic Area Council
Pace Energy Project
Pennsylvania Electric Company
Project for Sustainable FERC Energy Policy
Union of Concerned Scientists

Option 2-G

The Northeast Coalition[7]

Proposal on Post-Mediation Governance

The following proposal represents a comprehensive and integrated package, the components of which are not severable.

1. Establishment

a. Immediately after the issuance of a FERC order in this proceeding, a new limited liability company or other limited liability entity, with a Transition Board, should be established.
b. This Board will manage the implementation of the Business Plan during the transition to a new RTO for the Northeast.
c. The newly formed company, at the end of the transition, would become the new RTO (or part of a new hybrid RTO along with one or more ITCs) for the Northeast.
d. The corporate structure selected for the new RTO shall be subject to satisfactory resolution of issues related to existing tax-exempt financing of certain participants and other issues related to public, cooperative, and governmental entities.
e. The Transition Board will consider reliability, efficiency and identifiable environmental consequences of its policies and operations to balance, as reasonably as possible, the risks of harm to the environment against the benefits to be derived from proposed actions.
f. The stakeholder process should be established before the Transition Board can take any action.

2. The Transition Board

a. Transition Board

1) The Transition Board's directors initially should be chosen by, and from, the Boards of the existing ISOs. This will ensure continuity and that the new Board has experience with the reliability and market issues facing the Northeast.
2) The Transition Board will be comprised of 13 members, including three from each existing ISO's Board (9 members), and 4 new independent directors not currently on one of the ISO Boards to be selected by stakeholders.[8]

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[7] A list of supporters of Option 2-G follows the description of Option 2-G. A list of those parties supporting the board composition portion of Option 2-G is included as part of Appendix E.

[8] Criteria shall be established for the 4 additional Board members to achieve balanced experience necessary for effective Board composition.

3) The voting structure of the Transition Board will be by simple majority of the installed Transition Board. The Transition Board may take actions prior to the addition of the new directors.
4) Directors of the existing ISOs may be permitted to serve as Directors on the Transition Board without resigning their current positions. This will ensure maximum coordination and cooperation among the ISOs during the transition.
5) The Transition Board would serve during the transition to one RTO for the Northeast.
6) The Transition Board's fiduciary duties must be to implement the business plan consistent with maintaining for the public a safe and reliable electric system, creating and maintaining a robust, competitive, nondiscriminatory marketplace. These duties shall include, but not be limited to, preserving local and control area reliability, overall market efficiency, and the effectiveness of market power mitigation measures. The Board further must ensure that no constituency or constituencies have any undue influence.
7) The Transition Board's decisions on market design will be based on PJM Platform with needed modifications to accommodate best practices from New York and New England before start-up.

b. Permanent Board

1) The Transitional Board should decide issues related to permanent governance with input from stakeholders pursuant to Section 5 below. Decisions with regard to selection of Permanent Directors shall be a priority issue for resolution as soon as possible.
2) The Transition Board members will be eligible to become permanent board members.
3) The Permanent Board's fiduciary duties must include maintaining for the public a safe and reliable electric system, creating and maintaining a robust, competitive, nondiscriminatory marketplace. These duties shall also include, but not be limited to, preserving local and control area reliability, overall market efficiency, and the effectiveness of market power mitigation measures. The Board further must ensure that no constituency or constituencies have any undue influence.

3. The Transition Board's Responsibilities

a. The Transition Board's responsibility should be to carry out the RTO Business Plan in conjunction with advice and input from stakeholders, but the Transition Board shall not be empowered to submit filings under Section 205 of the Federal Power Act.[9, 10] If disputes arise between stakeholders and the Transition Board, they may be submitted to dispute resolution (described below) and, if necessary, to FERC.

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9 New York Department of Public Service believes that the Transition Board should have 205 rights to implement the business plan.

10 NY Multiple Intervenors all believe that stakeholders should retain section 205 rights.

b. The Transition Board, in conjunction with stakeholders, initially will concentrate on the design and planning of a single market for the Northeast and related issues, and it will attempt to resolve these issues expeditiously.

c. There shall be no prejudgment one way or the other regarding whether one or more ITCs or similar organizations will or will not be part of the RTO design for the Northeast. As described herein, it may be determined that initially there will be one or more ITCs or similar organizations, or it may be determined that initially there will not be any ITCs or similar organizations.

d. The Transition Board shall not prejudice the organizational structure or governance of the RTO, except that the Permanent Board shall constitute the initial Board of the organization within the RTO fulfilling ISO functions, including, but not necessarily limited to, market and related operational responsibilities.

e. As early as possible, the Transition Board, through its staff, will enter into negotiations with proponents of one or more ITCs or similar organizations and with other Transmission Owners regarding the potential divisions of RTO responsibilities among the ITC(s) or similar organizations that may form, other Transmission Owners, and the ISO within the RTO. The Board's staff will keep all stakeholders fully informed at all times about these negotiations through the advisory stakeholder process that is established, and it will solicit and consider stakeholder advice and input regarding the subject matter of these negotiations. If these negotiations do not produce an agreement regarding potential divisions of functions, then, a dispute may be submitted to dispute resolution (described below) and, if necessary, to FERC.

f. Except with respect to its decisions regarding its positions in the above-described negotiations, and except as stated in paragraphs (g) and (h), the Transition Board shall not be responsible for determining the organizational structure and governance of the RTO insofar as they relate to whether or not the RTO will have a hybrid organizational structure and, if so, its nature, or the formation of potential ITC(s) or similar entities or for implementing those portions of the RTO Business Plan that relate solely to the responsibilities assigned to ITC(s), if any. The RTO responsibilities ultimately shall be managed in accordance with the outcome of the negotiations, if any, between the Transition Board and the proponents of ITC(s) or other similar entities and other Transmission Owners, or by the outcome of any dispute resolution, or by the Transition Board's developed transmission design (described below), all subject to approval of the Commission.

g. On a priority basis, the Transition Board will establish, with input from stakeholders, a market monitoring unit that is independent of any market participant and will detect and prevent market power abuse.

h. At all times, the Transition Board shall exercise decisional responsibility for market-related transmission rules, as necessary for the design, planning, and implementation of a single market.

i. The Transition Board, as necessary, may design fully integrated transmission-related tariff and other matters on a parallel track with the foregoing that would accommodate the initial implementation of the new RTO without ITCs (or similar entities), if they do not form prior to such initial implementation. However, the Transition Board shall not present proposals for this alternative for discussion among stakeholders during the first 7 months after the Commission order on the Judge's mediation report.

j. Consistent with an open architecture, nothing shall prevent the formation of ITC(s) or similar entities after initial formation of the single RTO for the Northeast.

k. The CEOs of the existing ISOs shall develop a reasonable transition plan to move the existing ISO functions into the ultimate RTO structure as established by the Transition Board.

4. Chief Executive Officer and Initial Staffing

a. The Transition Board should select and appoint a CEO.
b. The existing ISOs' CEOs should be eligible for this position.
c. The CEO appointed by the Transition Board must agree to serve on a full-time basis and may not by employed by another ISO.
d. The CEO should be a non-voting member of the Transition Board.
e. The Chairman of the Transition Board may not simultaneously be Chairman of an ISO.
f. Staffing would be drawn initially from the existing ISO staffs.

5. Transitional Stakeholder Process and Dispute Resolution

a. A new, advisory[11] stakeholder committee process shall be established to advise the Transition Board and to address all issues in the RTO Business Plan. The Transition Board will consider the views expressed by the majority of stakeholders, as well as minority views, on any material issue.
b. The stakeholder advisory process generally should utilize the two-tier governance model of ISOs, with voting protocols that prevent dominance by any group of stakeholders.
c. There also should be an advisory arrangement between the Board and the state regulatory commissions. As determined by the state commissions, one state regulatory commission representative should be permitted to attend Board meetings except with respect to executive sessions of the Board.
d. The Transition Board will provide the stakeholder committees with a written explanation supporting its decisions when contrary to the required majority of the relevant stakeholder committee.
e. The stakeholder process shall provide for meaningful and effective input from all sectors including without limitation representatives of renewable resources, demand management, distributed generation and environmental interests.
f. If a dispute arises between stakeholders, on the one hand, and the Transition Board, on the other hand, any party may submit the dispute to the FERC Dispute Resolution Service for expedited non-binding dispute resolution. A Third Party Neutral assigned by the Dispute Resolution Service will be appointed promptly, on a stand-by basis, to mediate each dispute for a period of one week (unless extended by agreement of all parties, including the Board, to the dispute).
g. If agreement is not reached through the assistance of the Dispute Resolution Service, the Third Party Neutral shall submit the dispute, along with a report of the mediation, to the FERC for resolution. The parties simultaneously shall submit briefs within 10 days. The FERC shall attempt to resolve the dispute within 20 days thereafter.
h. The parties to any dispute may waive the above-described mediation step and proceed directly to FERC for resolution of a dispute.
i. Notwithstanding anything herein to the contrary, the rights of any party under the FPA are preserved, including without limitation sections 203 and 205. In particular, while a FERC ruling on a dispute submitted to it shall resolve the issue for purposes of implementing the business plan, it shall not alter or restrict such rights.

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[11] NY Multiple Intervenors support stakeholders having section 205 rights.

6. Existing ISO Boards

a. Existing ISO Boards should continue with their present duties during the transition period, which should be as short as possible.

7. Funding

a. The existing ISOs should fund the new Board's activities pending the implementation of a FERC-approved self-funding mechanism.

SUPPORTERS OF OPTION 2-G

ISO

New York Independent System Operator, Inc. (“NYISO”)
IMO

Public Interest

New York Department of Public Service
Massachusetts Division of Energy Resources
New York State Consumer Protection Board

Transmission Owners

New York
- Consolidated Edison Company of New York, Inc.
- Central Hudson Gas & Electric Corporation
- Long Island Power Authority
- New York State Electric & Gas Corporation
- Niagara Mohawk Power Corporation
- Orange and Rockland Utilities, Inc.
- Power Authority of the State of New York
- Rochester Gas and Electric Corporation

End-Users

New York Multiple Intervenors
Con Edison Solutions
City of New York

Municipal Electric Systems

Municipal Electric Utilities Association of New York State (“MEUA”)
City of Jamestown Board of Public Utilities
Delaware Municipal Electric Corp. (“DEMEC”)
City and Towns of Hagerstown, Thurmont and Williamsport, MD, and Front Royal, VA

Other Suppliers

The E Cubed Company, LLC
Joint Supporters
Distributed Power Coalition of America
Capstone Turbines
Indeck-Maine,
Affiliates of Ridgewood Power
Ontario Power Generation
Con Edison Energy

Option 3-G

The Pennsylvania Public Utility Commission

Proposal on Post-Mediation Governance[12]

General Principles of Governance:

- Open, collaborative and transparent deliberative and issue resolution process.
- Governance by a single independent non-stakeholder board with clear and single lines of authority over RTO management, employees and Section 205 filing authority necessary to implement a successful transition to a regional RTO.
- Quasi-independent Market Monitor with Section 205 filing authority necessary to file market power fixes and to compel the furnishing of timely and complete market information by market participants necessary for the monitoring function.

RTO

- Constituted as a limited liability organization, permitted to engage in lines of business not inconsistent with its role through for-profit limited liability subsidiaries.[13]
- Governed by an independent board, initially selected by and from existing ISO boards, later to be selected by stakeholders.

RTO Board

- Appointed soon after the issuance of a final mediation order by FERC.
- Board is in charge of all RTO implementation activities, including market and software design, tariffs and ongoing operations.
- Board is responsible for finance and budgets with consultation with advisory committees.
- Composed of board members from the three existing ISOs in accordance with relative loads, selected by each existing board – five from PJM, three from NY ISO, two from ISO NE, including RTO Chief Executive Officer.[14]
- CEO is selected by the board, and is also a voting member of the board. Total number of board members: eleven.
- After implementation is complete or four years (whichever occurs first), board members serve staggered five-year terms (two seats each year); CEO serves at pleasure of board. Election by simple and sector majority vote of members.

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[12] The supporters of Option 3-G are listed following the description of Option 3-G.

[13] The New Jersey Division of Ratepayer Advocate would state this concept as follows: “The RTO should be constituted as a limited liability organization permitted to engage in lines of business not inconsistent with its role, with proceeds used to offset the RTO’s expenses; organized with special consideration given to the ability of state consumer advocate agencies and municipal electric utilities to participate as members.”

[14] MAPSA would add two independent board members not from any existing region.

- Board members and candidates to be independent from all market participants.
- Board has all Federal Power Act Section 205 authority with respect to RTO tariffs and activities, shared 205 authority with respect to market power issues. Where Board and stakeholder advisory committees differ, board must explain to FERC why it has chosen a particular course of action.
- Agreement with state regulatory commissions memorialized by a memorandum of understanding to discuss matters of mutual interest and the furnishing of mutual advice and assistance in support of the regional wholesale market. No proprietary data to be shared without appropriate agreements and safeguards.

Market Monitoring Unit[15]

- Quasi-independent from RTO (budget and support would continue to be provided by RTO, subject to FERC review). MMU has Section 205 authority with respect to market power issues.
- MMU would have the right to examine all market data and to compel the production of timely information from market participants.
- MMU responsible for production of regular reports on the market and to respond to requests of the RTO or any member for a report on alleged exercise of market power or market abuse.
- MMU would have enforcement powers and to remedy market power and abuses by implementing market fixes, penalties or sanctions as FERC may authorize. MMU should not have power to retroactively modify market results except those obtained by fraud, collusion or actions contrary to filed tariffs or market rules.

Benefits:

The essence of this proposal is that a single line of authority, rather than multiple lines of authority, should guide and implement the process of forming a northeast regional RTO. Thus, we urge the formation of a single board. Other proposals presented in this mediation envision *four* boards, consisting of the three existing boards of the existing ISOs. In this proposal, a single board exercises Section 205 authority, with advice from a defined stakeholder committee process.

In other proposals, the three ISO boards and *some* transmission owners will continue to exercise existing Section 205 authority. They also intend the creation of a weak transition board, which has no 205 authority, and give that “transitional board” the unenviable task of harmonizing the factions without adequate authority. In addition, the management and staff of the existing entities, under the “transition board” proposals would be required to answer to two or more lines of authority in carrying out the required development and implementation of a single regional RTO.

Together with the proposed stakeholder governance proposal (outlined below), we propose a comprehensive approach to RTO governance based upon, but not identical to the PJM model. It is designed to give clear authority to the independent board to carry out the mission of the organization, while obligating that board to work with and be responsive to the views of a well defined, inclusive and legitimate stakeholder committee process.

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15 The Maryland Office of Peoples Counsel does not join in the Market Monitoring Section of these comments.

Stakeholder Committee Governance:

General Principles of Stakeholder Governance:

- Open, collaborative and transparent deliberative and issue resolution process.

Committee Structure:

- Advisory committees to consist of one standing committee (Members Committee) and six standing subcommittees (Finance, Reliability, Tariff, Operations, Markets and Public Interest/Environmental).
- Members Committee and subcommittees have the right to form a working group by request of five or more members on any topic.
- Standard voting protocol for matters involving modification or addition to an RTO tariff, a simple majority and sector majority vote would be required. For other matters, a simple majority vote would be required. Five sectors: Transmission, Generation, End User, Load Serving Entity/Reseller, and Public Interest Organization. Participants would self select their sector. Corporate entities with multiple affiliates may split their vote, but may not have more than a single sector or individual vote. Distribution of each single sector vote on the question is determined by the vote percentages within the sector.

Members

- Two classes of members: Market Participants/Transmission/End Users and Public Interest members. Market Participants must be signatories to RTO operating and reliability agreements, plus any other agreements required by their market participation. All market participants share in RTO liability. Public Interest members consist of non-profit governmental agencies such as Consumer Advocate Offices and Energy Offices and non-governmental organizations. No liability assumption obligation for Public Interest members.
- State and federal regulatory agencies with direct regulatory jurisdiction over rates, terms or conditions of transmission service or market participants would not be eligible for RTO membership, but would have full right of participation in committee activities.

Benefits:

The above stakeholder governance proposal provides the framework for an open stakeholder advisory governance process with a balance of interests, not dominated by any single interest category.

<u>SUPPORTERS OF OPTION 3-G</u>

Delaware Public Service Commission
Maryland Office of Peoples Counsel
New Jersey Board of Public Utility Commission Staff
New Jersey Division of Ratepayer Advocate
Mid Atlantic Power Supply Association (“MAPSA”)
New Power Company
Pennsylvania Public Utility Commission
Pennsylvania Office of Consumer Advocate

Stakeholder Governance Strawman

This strawman proposes milestones and a process for resolving issues related to the Stakeholder Governance of the Northeast RTO. In addition, it suggests some principles and a framework upon which the Stakeholder Governance may be constructed.

The strawman describes the PJM platform for stakeholder participation, as a starting point. The participants did not reach consensus on a number of significant features of stakeholder governance, and this is reflected in the presentation of options concerning:

- the number and definition of stakeholder sectors that will be created,
- the allocation of voting weight to each sector,
- and stakeholder voting protocols

In addition, resolution by the Commission, of whether stakeholders will have a decisional or advisory role in the Northeast RTO is a critical issue around which a number of the other, unresolved governance features, revolve.

A. Stakeholder Governance

The essential features of the PJM Stakeholder Governance process are described below. The five sector PJM model, and its voting protocols, is one of several options presented in this Stakeholder Governance Strawman.

PJM Platform

- Members Committee votes on a sector basis: each member (and its affiliates) chooses annually one of five sectors in which it is qualified to vote; each sector has a vote of 1.00, divided (as decimal numbers) between the affirmative and negative votes cast within the sector; action by the Members Committee ("MC") requires affirmative sector-vote of greater than 0.667 times the number of sectors voting. Voting within sectors is on a <u>per capita</u> basis. There are no formal sub-sectors.
- The five PJM sectors are Generation Owners, Other Suppliers, Transmission Owners, End-use Customers, and Electric Distributors. The Electric Distributors sector has not yet met the minimum requirement of five members and therefore is not yet active. There are no formal sub-sectors.
- Active advisory committee structure. The Operating Agreement specifies three standing subcommittees: Energy Market Committee, Planning Committee, and Operating Committee. Other standing committees, user groups, task forces, and working groups formed as deemed appropriate by members. All committees and working groups are open to all interested stakeholders. PJM staff chair the stakeholder committees, except for the Members Committee, Transmission Owners Agreement Administrative Committee, the Reliability Committee, and the user groups, all of which are chaired by stakeholders. Meetings of the Members Committee and all other committees are open to the public.
- State consumer advocate offices (and curtailment service providers under a pilot program) can become members under special rules that limit their liability. The FERC and state utility commissions may each nominate a representative to serve as *ex officio*, non-voting members.
- The OA specifies that one of the user groups shall be comprised of <u>bona</u> <u>fide</u> public interest and environmental organizations. Proposals approved by more than 75% of the members of a user group must be considered by the Members Committee at their next meeting. If the MC

rejects a user group proposal or recommendation, then, upon vote of 90% of the members of the user group, the proposal may be submitted directly to the Board.

- Operating Agreement also establishes a stakeholder Finance Committee to review the budget and make a recommendation to the Board on approval of the budget.
- PJM also has a Liaison Committee to facilitate communication between the Board and the Members of the LLC. The Liaison Committee is composed of three members of the Board (including the President), the current chair and vice-chair of the Members Committee, the immediate past chair of the MC, the chairs of the Reliability Committee and Transmission Owners Agreement Administrative Committee, and any additional representatives needed to ensure that all PJM member sectors are represented.
- PJM also has a communications protocol with the state regulatory commissions in its region, providing a mechanism for regular communication with the states.
- Reliability Assurance Agreement establishes Reliability Committee, composed of all load-serving entities, to vote on amendments to agreement and on reliability matters, including reserve requirement. [7/12/01 FERC order held that Board must have exclusive authority to file changes to reliability requirements under FPA §205, with Reliability Committee continuing to have a role as advisor to Board; PJM also required to study feasibility of expanding membership of Reliability Committee to more market participants.]
- Transmission Owners Agreement establishes Transmission Owners Agreement Administrative Committee, composed of representatives of the signatories, to provide their advisory input to the Board.

B. Principles for RTO Stakeholder Governance

- The following principles will guide RTO Stakeholder Governance procedures:
  - Participation should be inclusive and affordable.[16]
  - All stakeholders have reasonable, fair and equal access to the RTO Board.
  - Stakeholder meetings will be noticed and open to all interest parties, including governmental agencies.
  - Fair and balanced representation of all stakeholders.
  - All committees shall follow a uniform, open and collaborative discussion process.
  - Stakeholders will develop and rely upon a process that allows disparate views to be heard and resolved at the committee level.[17]

C. Process and Milestones

- Within two weeks after Judge Young has issued his report, interested stakeholders will meet to resolve the outstanding issues related to the organization of stakeholder governance. A number of stakeholders request the Commission to appoint a mediator or a settlement judge to oversee the post 45 day stakeholder governance discussions.
- One issue to be resolved during the post-45 day mediation process is whether stakeholders should begin the formation of one or more committees prior to the issuance of a FERC order

[16] A definition of "affordable" should be agreed upon.

[17] One suggestion is to follow the guidance provided by American National Standards Institute, *Procedure for the Development and Coordination of American National Standards* (2001) Sections 1.0 - 1.2.7. Available on http://www.ansi.org.

in this proceeding. Early formation of stakeholder committees will provide a mechanism for providing stakeholder advice to the Board, as soon as it is constituted. This step assumes, at a minimum, that the outstanding issues can be resolved so as to reach consensus. Some participants express a reluctance to proceed with committee formation prior to the issuance of a FERC order.

D. Interim or Permanent Governance

Any option and all features may apply either to an interim or permanent governance structure.[18]

E. Role for Stakeholders

Two options are described below, proposing alternatives to the extent permitted by the Commission:

- Option 1: RTO Stakeholders will act in an advisory capacity to the RTO Board.
- Option 2: Stakeholders retain decisional authority with regard to certain matters.

F. Stakeholder Classes

- For any option, Stakeholders will be organized into the following two classes.
  - Class 1 = General Members. This class signs RTO agreements and assumes liability for RTO.
  - Class 2 = Public Interest Members. This class consists of non-profit organizations and governmental organizations. This class would not be obligated to assume any RTO liabilities. A nominal membership fee will be imposed on Class 2 members.

G. Stakeholder Sectors

- For any Sector Option, stakeholders will be permitted to select the sector in which they participate, provided they are qualified.
- For any Sector Option, a decision will need to be made with regard to the voting weight assigned to each sector. The alternatives are:
  - Sectors have equal voting weights
  - Sectors do not have equal voting weights

- Sector Option 1. "PJM Platform Proposal"
  Stakeholders will be organized into the following five sectors:
  1. Transmission Owners
  2. Generation Owners
  3. End Users
  4. Other Suppliers
  5. Electric Distributors
  - Voting protocols will be the same as those used in PJM.

18 The Stakeholder Governance options described below are intended to supplement but not to alter the governance material in Options 1-G, 2-G, and 3-G found in this document.

  - Governmental agencies with regulatory responsibilities over market participants would not be eligible for stakeholder voting status, but would be entitled to observe and otherwise fully participate in committee and working group activities.

- Sector Option 2. "Four Sector Proposal"
  - Stakeholders would be organized according to the four populated sectors currently in PJM (Transmission Owners, Generators, Other Suppliers, End Users), until an alternative arrangement is arrived at in post-mediation.
  - Definitions of the four sectors will be modified, if needed, so that all stakeholders will have an appropriate sector in which to participate.
  - Governmental agencies with regulatory responsibilities over market participants would not be eligible for stakeholder voting status, but would be entitled to observe and otherwise fully participate in committee and working group activities.

- Sector Option 3. "Five Sector Proposal"
  Stakeholders will be organized into the following five sectors, which may further be divided into sub-sectors:[19]
  1. Transmission Owners
  2. Generation Owners
  3. End Users
     a. Industrials
     b. Large Commercials
     c. Small Customers (Less than 1 MW)
     d. Consumer Advocates
  4. Other Suppliers / Load Serving Entities
     a. Wholesale Marketers
     b. Retail Load Serving Entities
     c. Curtailment Service Providers (Aggregators)
     d. Demand Resources
  5. Distribution Companies / Public Interest[20]
     a. Distribution Owners
     b. Co-Ops, Municipals, Transmission Dependent Companies
     c. State Power Authorities (NYPA, LIPA)
     d. Environmental Entities
     e. Alternative Generation Technologies
     f. Technology Providers
     g. Renewable Energy
     h. Distributed Generation
  - Governmental agencies with regulatory responsibilities over market participants would not be eligible for stakeholder voting status, but would be entitled to observe and otherwise fully participate in committee and working group activities.

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[19] For example, in New York, two sectors are divided into sub-sectors -- the End-Use Consumer Sector and the Public Power/Environmental Party Sector. Each sub-sector is allocated a fixed portion of the voting weight of the sector.

[20] Some parties believe that the entities listed as (e) through (h) are more properly classified within the "Other Suppliers/Load Serving Entities" sector.

- Sector Option 4. "Six Sector Proposal"
  Stakeholders will be organized into the following six sectors, which may be further divided into sub-sectors:
  1. Transmission Owners
  2. Distribution Companies
     a. Distribution Owners
     b. Co-Ops, Municipals, Transmission Dependent Companies
     c. State Power Authorities (NYPA, LIPA)
  3. Generation Owners
  4. End Users
     a. Industrials
     b. Large Commercials
     c. Small Customers (Less than 1 MW)
     d. Consumer Advocates
  5. Other Suppliers
     a. Wholesale Marketers
     b. Retail Load Serving Entities
     c. Curtailment Service Providers (Aggregators)
     d. Demand Resources
  6. Public Interest
     a. Environmental Entities
     b. Alternative Generation Technologies
     c. Technology Providers
     d. Renewable Energy
     e. Distributed Generation

  - Governmental agencies with regulatory responsibilities over market participants would not be eligible for stakeholder voting status, but would be entitled to observe and otherwise fully participate in committee and working group activities.

H. Stakeholder Voting

The options described below have a number of similar features. A significant difference between the voting options lies in whether individual sector voting totals are aggregated or not aggregated prior to reporting to the Board. In both options, voting criteria for the election of Directors is specified, in the event that stakeholders will be empowered to elect Directors.

- Voting Option 1:
  - There will be per capita voting within each sector.
  - Votes will be tallied across sectors to determine the total number of stakeholders that support or oppose a matter.
  - The results of the sector votes will be made available to the Board.
  - The Board will make provisions to hear majority and minority positions from the proponents of those views.

  - A parent company and its affiliates may have only one vote which they may cast entirely in one sector.[21]
  - There is general support for a supermajority voting rule for the purposes of providing stakeholder input to the RTO Board, and for the purposes of electing Board members. However, there was no agreement on the voting threshold to be adopted. Currently, New York requires a 58% vote, while New England and PJM require a 2/3rds majority. A suggestion was made that the supermajority voting criteria fall between 58% and 66%. This is a detail to be resolved during post 45 day mediation process.
  - In the event that a supermajority is not achieved, the Stakeholder decision or advice fails to pass.

- Voting Option 2:
  - There will be per capita voting within each sector.
  - Each sector would have a single vote, which would be split according to the number of Members within that sector. A five (5) Member sector with three (3) "yes" and two (2) "no" votes on a proposal before the Members Committee would be counted as casting 0.6 votes in favor and 0.4 votes against the proposal. The purpose of such sector voting is to provide informed guidance to the Board, and it is not anticipated that the Board would use such weighted sector voting except as discussed below concerning election of Board members.
  - For purposes of Member election of Board members a prospective Board member would be required to obtain both a simple and sector majority of all Members.
  - For purposes other than Member election of Board members, Member votes shall be tallied, on a sector basis, for the limited purpose of providing the Board with an indication of the Members' preferences by simple majority vote within each sector, but any such vote tallies shall not lessen the obligation of the Board to provide fair and reasoned consideration of all Member opinions.
  - The Board will make provisions to hear majority and minority positions from the proponents of those views.

I. Committees

- There will be a "Members" (or "Management") Committee.
- There will be a committee (or subcommittee) dedicated to Reliability.
- One proposal specifies the creation of four standing committees in addition to the Members and Reliability Committees: Market Design Committee; Transmission Planning and Interconnection Committee; Transmission Tariff and Rates Committee; Governance Committee.

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[21] A few entities prefer an option of splitting votes among affiliated companies between or within sectors. In that case, a stakeholder would make an annual designation of the fraction of its vote that each affiliate will exercise for that year.

- Another proposal recommended subcommittees reporting to the Members Committee; these subcommittees are: Finance, Reliability, Tariff, Operations, Markets, Public Interest and Environmental issues.
- Additional working groups and subcommittees may be formed, as necessary.
- User groups and other ad hoc groups may be formed at the request of any 5 members.

SECTION TWO

RTO Governance and Organizational Structure, ITCs, Market Monitoring and Mitigation, Costs, Financing and Recovery of Costs, and Information Release

Task One: **Identify the Basic Elements of the PJM Platform on Governance and Organizational Structure, ITCs, Market Monitoring and Mitigation, Costs, Financing and Recovery of Costs, and Information Release and the Differences from the Other ISOs in this Area, including Their Nominated Best Practices**

Complete: **Done**

I. Governance and Organizational Structure

A. Organizational Structure

PJM Platform

- Delaware limited liability company ("LLC")
- Operates on a profit-neutral basis
- LLC tax election is 'C' corporation tax status for purposes of IRS regulations.
- Market participants are members of the LLC.
- LLC, its directors, officers, and employees, and member-representatives on committees are not liable to members except in cases of gross negligence or willful misconduct; LLC indemnifies its directors, officers, and employees, and member-representatives on committees against third-party claims except in cases of willful misconduct.
- Two-tier governance structure: independent, non-stakeholder Board and stakeholder advisory[22] committee(s).
- Certain indemnity and funding obligations can be waived as to municipal electric systems applying for membership; tax-exempt financing is not otherwise addressed.

<u>*Major Differences for New York*</u>*:*

- *The NYISO is a not-for-profit corporation, organized under the Not-For-Profit Corporation Law of New York State, and qualified under Section 501-C of the United States Internal Revenue Code.*
- *The NYISO has special provisions to accommodate the needs of entities with tax-exempt financing. There are specific provisions which protect the tax-exempt financing for NYPA, LIPA and Con Edison, including scheduling provisions over certain LIPA facilities and special withdrawal provisions related to entities with tax-exempt financing requirements.*

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22 In addition to its advisory role, the Members Committee also has authority to amend the Operating Agreement and file such amendments with FERC.

- *NYISO has different liability and indemnification provisions under the OATT and Services Tariff. In addition, there are liability provisions in various FERC-approved agreements relating to the NYISO.*

<u>Major Differences for New England</u>:

- *[New England RTO proposal reflected a hybrid RTO structure consisting of an ISO and an ITC, with division of responsibilities]* ***[BP]***
- *ISO-NE is a Delaware not-for-profit non-stock corporation.*
- *ISO-NE is not taxed due to its status as a 501(c)(4) entity.*
- *Existing Directors are the members of the corporation.*
- *Two-tier governance structure: independent, non-stakeholder Board of ISO-NE and the New England Power Pool ("NEPOOL") (acting through the NEPOOL Participants Committee).*
- *New England has a "contract" structure: the relationship between the ISO and the NEPOOL participants is defined by a contract – namely, the Interim ISO Agreement – between the ISO and the NEPOOL Participants. The term of the Interim ISO Agreement runs through June 30, 2002. Termination is subject to FERC approval.*
- *Interim ISO Agreement provides that ISO-NE shall not be liable to the NEPOOL Participants for actions or omissions by the ISO in performing its obligations under the Agreement, provided it has not willfully breached the Agreement or engaged in willful misconduct. To the extent the NEPOOL Participants have claims against the ISO, the NEPOOL Participants may only look to the assets of the ISO for the enforcement of such claims and may not seek to enforce any claims against the directors, members, officers, employees or agents of the ISO who, the NEPOOL Participants acknowledge and agree, have no personal liability for obligations of the ISO by reason of their status as directors, members, officers, employees or agents of the ISO. Similarly, the NEPOOL Participants shall not be liable to the ISO for a failure to perform under the terms of the Agreement, unless that failure to perform was a willful breach of the Agreement. In no event shall either Party to the Interim ISO Agreement be liable to the other Party for any incidental, consequential, multiple or punitive damages, loss of revenues or profits, attorneys fees or costs arising out of, or connected in any way with the performance or non-performance of the Agreement.*
- *Under the Interim ISO Agreement, NEPOOL indemnifies, defends and saves harmless the ISO and its directors, officers, members, employees and agents from any and all damages, losses, claims and liabilities by or to third parties arising out of or resulting from the performance by the ISO under the Agreement or the actions or omissions of the NEPOOL Participants in connection with the Agreement, except in cases of gross negligence or willful misconduct by the ISO or its directors, officers, members, employees or agents.*

B. Board Composition, Rights, and Responsibilities

PJM Platform

- Eight-person independent Board, including President as a non-voting member

- Board candidates may not have been officers or employees of any Member or affiliate for five years before election; Board members can have no financial interest in any market participant.
- Search firm selects candidates for board election. The Operating Agreement specifies that four of the Board members must have experience in the areas of senior corporate leadership, or in finance, accounting, engineering, or utility laws and regulation. One Board member must have expertise in transmission dependent utilities; one must have expertise in the operation or planning of transmission systems, and one must have expertise in commercial markets and trading and associated risk management
- Individual Board members elected by Members of LLC to three-year terms (no term limits); terms are staggered with annual elections.
- Primary responsibilities of the Board are: (A) the safe and reliable operation of the grid, (B) the creation and operation of a robust, competitive, and non-discriminatory electric power market, and (C) ensuring that no Member or group of Members has undue influence over the operation of the PJM system.
- Board can file changes to tariff under FPA §205 without stakeholder approval
- As a result of 7/12/01 RTO order, Board has right to determine all reliability matters, including reserve requirement.
- Board has explicit right to file FPA §206 complaint to change any agreement or market rules without stakeholder approval.
- Board meetings are usually closed, except for Liaison Committee sessions; and Board members regularly attend stakeholder meetings to hear stakeholder perspectives.
- Established alternative dispute resolution ("ADR") process is set forth in organic documents for disputes among Members or between a Member and PJM. Any dispute under the PJM agreements that has not first been resolved through specified mediation procedures and that involves a claim of less than $1,000,000 is subject to binding arbitration.

Major Differences for New York:

- *The NYISO has a nine member Board of Directors, all of whom are independent of any New York market participants. The CEO of the NYISO is an ex-officio member of the Board.*
- *Pre and Post Board position employment conditions differ from PJM requirements. There are specific experience requirements for Board members in order to ensure a diversity of backgrounds.*
- *NYISO Board is self-perpetuating; Management Committee can recommend candidates; search firm may be used, but is not required; Board decision is final*
- *FERC and NYPSC staff are permitted to attend Board meetings.*
- *Board requires concurrence from Management Committee in order to file a tariff change under Section 205.* **[*possibly impacted by 7/12/01 FERC order*]**
- *Board has the right to make an independent Section 205 filing in "exigent circumstances". Such filings will sunset in 120 days absent concurrence of the Management Committee, or unless approved by FERC under FPA §206.* ***[possibly impacted by 7/12/01 FERC order]***
- *The NYISO's Dispute Resolution Process has provisions for non-binding mediation and for non-binding arbitration. Binding arbitration applies only when all parties agree that the decision will be binding or if the dispute involves a claim for less than $500,000.*

<u>*Major Differences for New England*</u>:

- *ISO-NE has ten-person independent Board, including Chief Executive Officer as voting member**. [BP]***
- *Chief Executive Officer not eligible to be Chairman of the Board**. [BP]***
- *Directors nominated and elected by Board members (i.e., board is self-perpetuating).*
- *Board candidates may not be a former executive officer of a participant or its affiliates for two years prior to election or be receiving continuing benefits, other than customary retirement-related benefits including, but not limited to, benefits under ERISA plans, supplemental retirement plans or non-pension post-retirement benefit plans, from a participant or any of its affiliates. Board members, their spouses and their minor children may not own nor purchase securities of any market participant. Board members may not have any material ongoing business relationship with any participant or any of its affiliates**. [BP**]*
- *Board is responsible for management of ISO-NE**. [BP**]*
- *ISO-NE is operator of NEPOOL Control Area and administrator of transmission and market arrangements in accordance with the NEPOOL transmission tariff, the Restated NEPOOL Agreement, and the System Rules and Procedures (including market rules).*
- *ISO-NE has sole responsibility to develop such new system rules and procedures as may be necessary to allow the ISO to carry out its obligations under the ISO Agreement. ISO-NE does not have § 205 rights for NEPOOL transmission tariff; does have rights to implement changes in market rules under circumstances specified in the Interim ISO Agreement and subject to FERC approval. The New England RTO order required that an RTO have §205 rights over market and tariff rules. The by-laws provide that the Board should possess a cross-section of skills and experience (such as, for purposes of illustration but not by way of mandate or limitation, experience in FERC electric regulatory affairs, electric utility management, corporate finance, bulk power systems, human resource administration, power pool operations, public policy, consumer advocacy, environmental affairs, business management and information systems).*
- *The Interim ISO Agreement provides for ADR for certain disputes between the ISO and NEPOOL; separate ADR process is specified for billing disputes.*
- *Board meetings are usually closed except for joint meetings with Advisory Committee. Board members meet quarterly with sector representatives.*

C. Stakeholder Role

PJM Platform

- Market participants, including facility owners, can become members of the LLC by signing the Operating Agreement and paying nominal annual fees.
- Board can waive any membership requirements to facilitate participation by public power entities.
- State consumer advocate offices (and curtailment service providers under a pilot program) can become members under special rules that limit their liability. The FERC and state utility commissions may each nominate a representative to serve as *ex officio*, non-voting members.

- Members, through the Members Committee, elect the Board.
- Members Committee can amend the Operating Agreement and all schedules to OA (including market rules[23]), subject to prior Board review and comment, and file such amendments with the FERC. Such amendments are subject to FERC approval.
- Members Committee advises the Board.
- Members Committee votes on a sector basis: each member (and its affiliates) chooses annually one of five sectors in which it is qualified to vote; each sector has a vote of 1.00, divided (as decimal numbers) between the affirmative and negative votes cast within the sector; action by the Members Committee requires affirmative sector-vote of greater than 0.667 times the number of sectors voting. Voting within sectors is on a per capita basis. There are no formal sub-sectors.
- The five PJM sectors are Generation Owners, Other Suppliers, Transmission Owners, End-use Customers, and Electric Distributors. The Electric Distributors sector has not yet met the minimum requirement of five members and therefore is not yet active.
- Active advisory committee structure. The Operating Agreement specifies three standing subcommittees: Energy Market Committee, Planning Committee, and Operating Committee. Other standing committees, user groups, task forces, and working groups formed as deemed appropriate by members. All committees and working groups are open to all interested stakeholders. PJM staff chair the stakeholder committees, except for the Members Committee, Transmission Owner Agreement Administrative Committee, the Reliability Committee, and the user groups, all of which are chaired by stakeholders. Meetings of the Members Committee and all other committees are open to the public.
- The OA specifies that one of the user groups shall be comprised of bona fide public interest and environmental organizations. Proposals approved by more than 75% of the members of a user group must be considered by the Members Committee at their next meeting. If the MC rejects a user group proposal or recommendation, then, upon vote of 90% of the members of the user group, the proposal may be submitted directly to the Board.
- Operating Agreement also establishes a stakeholder Finance Committee to review the budget and make a recommendation to the Board on approval of the budget.
- PJM also has a Liaison Committee to facilitate communication between the Board and the Members of the LLC. The Liaison Committee is composed of three members of the Board (including the President), the current chair and vice-chair of the Members Committee, the immediate past chair of the MC, the chairs of the Reliability Committee and Transmission Owners Agreement Administrative Committee, and any additional representatives needed to ensure that all PJM member sectors are represented.
- PJM also has a communications protocol with the state regulatory commissions in its region, providing a mechanism for regular communication with the states.
- Reliability Assurance Agreement establishes Reliability Committee, composed of all load-serving entities, to vote on amendments to agreement and on reliability matters, including reserve requirement. [7/12/01 FERC order held that Board must have exclusive authority to file changes to reliability requirements under FPA §205, with

[23] FERC's 7/12/01 orders on NYISO and ISO-NE RTO held that the independent board must have sole authority to make changes to market rules without first obtaining approval from a stakeholder committee.

Reliability Committee continuing to have a role as advisor to Board; PJM also required to study feasibility of expanding membership of Reliability Committee to more market participants.]

- Transmission Owners Agreement establishes Transmission Owners Agreement Administrative Committee, composed of representatives of the signatories, to provide their advisory input to the Board.
- PJM West agreements establish West Reliability Committee and West Transmission Owners Agreement Administrative Committee, similarly composed and empowered, to address similar matters in PJM West area.

Major Differences for New York:

- *Three agreements govern the organization of the NYISO: the "NYISO Agreement"; the "NYISO/Transmission Owners Agreement"; and the "NYISO/NYSRC Agreement."* ***[possibly impacted by FERC's 7/12/01 order]***
- *The NYISO has a two-tier governance structure. There are three standing committees of market participants: the Management Committee is the principal stakeholder committee; the Business Issues Committee and the Operations Committee report to the Management Committee; each have decision-making authority over certain matters which are specified in the "NYISO Agreement." There are numerous other standing subcommittees, working groups and ad-hoc task forces which report to the three standing committees.* ***[possibly impacted by 7/12/01 FERC order]***
- *The stakeholder committees are chaired by market participants, elected by the respective committees.*
- *The NYISO has a Liaison Committee which is comprised of a rotating membership among Market Participants, which meets with the Board on a monthly basis. In addition, there are biannual joint meetings of the Board and the Management Committee.*
- *The Management Committee hears appeals of, and may overturn actions of, the two lower committees.* ***[possibly impacted by 7/12/01 FERC order]***
- *Management Committee concurrence is required for a Section 205 tariff filing to be made.* ***[possibly impacted by 7/12/01 FERC order]***
- *The market participant committees are organized into five sectors: Transmission Owners, Generators, End Use Consumers, Other Suppliers and Public Power/Public Interest/Environmental. Each sector has a fixed share of the total voting weight (which varies by sector), and each sector may have its own allocation method for apportioning votes among its members. (Public power and state consumer advocates are voting members of the NYISO committees.)*
- *A matter that comes before a market participant committee is passed if it receives a 58% vote of the members at that meeting.* ***[possibly impacted by 7/12/01 FERC order]***
- *The Board of Directors hears appeals of actions taken by the Management Committee and may overturn actions of that Committee on appeal, or on its own motion.* ***[possibly impacted by 7/12/01 FERC order]***

- *The New York State Reliability Council sets the Installed Reserve Requirement for the New York Control Area*[24] *and certain other reliability requirements There is an "NYSRC Agreement" which governs that organization, which has a multi-stakeholder governance structure that is separate and distinct from that of the NYISO.*

<u>Major Differences for New England</u>:

- *NEPOOL Participants Committee ("NPC") adopts and files changes to NEPOOL transmission tariff and Market Rules (subject to transmission owner rights and the ISO rights specified above) (July 12 New England RTO order specifies that in an RTO, market participant committees such as NEPOOL's should serve a purely advisory role). The NPC is chaired by a participant.*
- *NPC has certain reliability responsibilities such as its approval of interconnection applications and establishment of objective capability based on consultation with the ISO and NEPOOL technical committees.*
- *The Restated NEPOOL Agreement provides for a Liaison Committee between the ISO and NEPOOL. The ISO-NE Board holds meetings with stakeholder sectors on a periodic basis.*
- *The ISO-NE Board meets with NECPUC at least twice yearly.*
- *The Restated NEPOOL Agreement provides for appeals of NPC actions to an independent NEPOOL Review Board of and for stays of those actions pending such appeals.*
- *NPC has five sectors – transmission, generation, suppliers, end users and public power. Each sector has a twenty percent vote of the total vote and a sixty seven percent vote is needed for passage.*
- *NEPOOL has three technical committees (chaired by ISO staff) in addition to NPC: Markets, Tariff and Reliability. NEPOOL has numerous ad hoc committees chaired by participants.*
- *ISO-NE Board has an Advisory Committee(that meets periodically with the full Board) of members representing a broad spectrum of interests including public officials and consumer advocates. At least two Board members attend all Advisory Committee meetings. Board meetings are open when the Board meets with the Advisory Committee.* ***[BP]***

D. RTO Expansion

PJM Platform

- Operating Agreement allows for addition of transmission owners outside of existing control area.
- For PJM West expansion, existing OA and Tariff retained and amended to apply to multiple control areas.
- Existing Board manages expansion to additional control areas.

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24 FERC's 7/12/01 order on PJM's RTO proposal held that the independent board, rather than a stakeholder reliability committee, must have exclusive authority to file changes to reliability requirements under FPA §205.

<u>Major Differences for New York</u>:

- *In New York, there are no specific provisions for expansion of the ISO/RTO beyond its current boundaries.*

<u>Major Differences for New England</u>:

- *There are no specific provisions for expansion. [The ITC proposal for New England contained provisions for geographic expansion of the ITC.]*

E. Stakeholder-identified Sub-issues Pertaining to Governance and Organizational Structure

- See Appendix A-1

II. Independent Transmission Companies

PJM Platform

- PJM West Transmission Owners Agreement explicitly recognizes that one or more West Transmission Owners may establish an Independent Transmission Company and, subject to FERC approval, may desire to transfer certain rights and obligations (to be determined) pertaining to its transmission facilities from PJM to an Independent Transmission Company (or make such rights and responsibilities subject to coordination between an ITC and PJM), while PJM continues to perform certain functions (to be determined), including administration of markets.
- Independent Transmission Company is defined in the PJM West TOA as an entity that owns transmission facilities and sells transmission services, but excludes a transmission owner if it (or its affiliates) sell, broker or generate electricity for sale in energy markets, except for electricity used by the ITC itself or used for the provision of ancillary services.
- Parties reserve the right to take any position before state and Federal regulatory authorities regarding the transfer of RTO functions to an ITC, provided that all parties must first attempt to negotiate in good faith a mutually acceptable arrangement for the transfer or sharing of functions.
- PJM advised the Commission that it would apply the same principles to transmission owners outside PJM West.
- The PJM transmission owners specifically retain the right to transfer or convey all or any part of their assets, including transmission facilities, and to terminate the relationship with PJM in connection with the creation of a transmission company to own or operate their transmission facilities.

<u>Major Differences for New York</u>:

- *The NYISO Tariffs make no specific provisions for the potential development of an ITC in NY. There is also nothing that specifically precludes such an entity from forming.*
- *The NYISO/TO Agreement specifically reserves the right to the TO's in New York to dispose of their transmission assets, to withdraw their assets from the NYISO's*

control, or to terminate their participation in the NYISO upon notice and FERC approval.

Major Differences for New England:

- *Restated NEPOOL Agreement provides that each New England Transmission Owner retains specified rights, including the right (individually or collectively) to amend or terminate its relationship with ISO in connection with the creation of an alternative arrangement for the ownership and/or operation of its transmission facilities on an unbundled basis (e.g., a transmission company), subject to necessary regulatory approvals and approvals required under Restated NEPOOL Agreement.*

New England ITC Alternative:

In its July 12, 2001 "Order Granting, In Part, and Denying, In Part, Petition for Declaratory Order," the Commission acted upon an RTO proposal for New England, including a request for Commission rulings on the Northeast Independent Transmission Co., LLC.("ITC") that would be part of the RTO. The Commission stated:

> *We appreciate the time and effort invested by the Petitioners in developing their proposals, especially in the area of governance structure. Because the work undertaken on these issues may be applicable to the Northeast region as a whole, we will address herein each of the RTO characteristics and functions as they apply to Petitioners' filing in order to provide guidance to the parties as they consider the formation of a single RTO for the Northeast.*

96 FERC ¶61,063, slip op. at 3. The Commission specifically found that "under Petitioners' proposal, NE ITC's Managers, the entities that would operate the ITC, would perform their duties in a manner that would satisfy the independence characteristic." Id., slip op. at 11. Rehearing of that determination has been sought. Also, in the absence of specific contractual language and binding agreements governing the relationship between ISO-NE and the ITC, the Commission reserved judgement regarding (1) the division of responsibilities between ISO-NE and the proposed ITC (id., slip op. at 7) and (2) the hybrid RTO's compliance with the operational authority criteria of Order No. 2000 (id., slip op. at 18). The following is a description of the ITC governance and organizational structure, as set forth in the New England RTO proposal:

A. Organizational Structure

The ITC would be a Delaware limited liability company ("LLC"), with the following attributes:

- *Transmission owners that initially participate in the ITC and that purchase economic interests in the ITC would be the initial Members of the LLC.*
- *Class A Shares could be held by transmission owners participating in the ITC that are Market Participants.*

- *Class B Shares would relate solely to the voting rights of independent Managers on the ITC Board of Managers and would include no rights in the economic equity interests in ITC. Class B Shares would be issued to an orphan company or a fiduciary trustee and not be owned by any participant in the ITC.*
- *Class C Shares could not be held by Market Participants, but could be held by participants in the ITC that are not Market Participants, as determined by FERC.*

Transmission owners could participate in the ITC in a variety of ways:

- *A transmission owner could become a Member of the ITC. Each transmission owner Member would enter into a Participation Agreement to transfer responsibility for the management and operation of its transmission facilities to the ITC.*
- *A transmission owner could give the ITC operational control over its transmission facilities by executing only the Participation Agreement, without becoming a Member of the ITC. Such a transmission owner is referred to as a non-investing participating transmission owner ("NIPTO"). Such NIPTO participation in the ITC would be very similar (virtually identical) to a transmission owner turning control of its facilities to an ISO.*
- *A transmission owner could transfer ownership of its transmission assets to the ITC in exchange for consideration.*
- *The ITC would be authorized to enter into other arrangements, as necessary, to permit the integration of other transmission facilities with those under the control of the ITC.*

B. Board Composition, Rights and Responsibilities

The ITC would be governed by a Board of Managers consisting of three classes of Managers:

- *Class A Managers would represent the interests of transmission owners participating in the ITC that are also Market Participants.*
- *Consistent with Order No. 2000's five year "safe harbor" limitation on Market Participant ownership in an RTO, the voting rights of Class A Managers would be limited, in the aggregate, to 15 percent of all voting shares in the Board of Managers. No Class A manager could have more than 5 percent of all voting shares.*
- *Class B Managers would be required to be independent of any transmission owner or Market Participant and would be selected with stakeholder input, as described below.*
- *Class B Managers, in the aggregate, would have all voting shares in the Board of Managers not held by either Class A Managers or Class C Managers, if any.*
- *Each of the four Class B Managers would have one fourth of all votes held by Class B Managers in the aggregate.*
- *Class C Managers would be independent of any Market Participant and would represent other entities with an economic equity interest in the ITC, including transmission owners participating in the ITC that are non-Market Participants, as determined by FERC.*

- *Initially, each Class C Manager would have no more than 15 percent of all voting shares.*
- *In the aggregate, Class B Managers and Class C Managers would have a majority of votes on the Board, ensuring governance independent of Market Participants.*

There would be four Class B Managers on the ITC Board of Managers selected through the following process:

- *Three of the Class B Managers would be chosen from pools of candidates identified by a nationally-recognized executive search firm.*
- *The search firm would select two pools of three or more candidates for the Class B Manager positions. In Pool 1, the search firm would select three or more candidates with executive experience in the electric power industry. In Pool 2, the search firm would select three or more candidates with executive experience in other industries.*
- *Each candidate and his/her immediate family must be independent of any transmission owner or Market Participant and must not be affiliated with any entity with an economic equity interest in the ITC.*
- *Any stakeholder or member of the ITC may suggest that the search firm consider particular candidates for Class B Manager positions.*
- *The members of the ITC would choose two candidates from Pool 1 and one candidate from Pool 2.*
- *The Stakeholder Advisory Group, by a vote of 75% of its members, could vote to reject a proposed Class B Manager chosen in the preceding step.*
- *If any of the three proposed Class B Managers selected through this process is rejected by a vote of the Stakeholder Advisory Group, another Class B Manager would be chosen pursuant to the same process.*
- *The fourth Class B Manager would be the CEO of the ITC.*
- *The CEO would be selected by an Interim Committee, comprised of a representative from each of the transmission owners initially participating in the ITC. Like other Class B Managers, the CEO must be independent of any transmission owner or Market Participant.*

Consistent with the requirements of Order No. 2000, the ITC would arrange for an independence compliance audit to be conducted two years after the Commission approves the RTO and every three years thereafter.

The primary responsibility of the Board of Managers is to oversee the ITC in carrying out those functions and characteristics of an RTO assigned to the ITC, consistent with the division of responsibilities negotiated with ISO New England.

C. Stakeholder Role

- *A Stakeholder Advisory Group ("SAG") with regularly scheduled meetings would be the primary vehicle for stakeholder input to the ITC.*
- *The SAG would be made up of representatives from each stakeholder sector.*

- *The proponents of the ITC identified the following matters as those in which stakeholders likely would have an interest and where stakeholder input could help shape the ITC's actions, policies and proposals:*
  - *Transmission System Planning and Expansion;*
  - *Transmission Rates and Tariff Design (including interconnection; seams and inter-regional coordination issues);*
  - *Operations;*
  - *Selection of Class B Managers (as described above).*
- *The ITC or any member of the SAG may convene special meetings when particularly important matters are being considered by the ITC.*
  - *At such meetings, the ITC will respond to any reasonable requests for information related to the matters being considered by the ITC and will solicit stakeholder input on the anticipated action.*
  - *Before the ITC takes action on the matters being considered, it will prepare a report describing issues raised by the stakeholders. Written comments submitted by the stakeholders will be appended to the report. The report will be provided to all stakeholders who request it, and will be included with any filing on such matters submitted to the FERC.*

D. RTO Expansion

- *The ITC was expressly designed to facilitate the expansion of the RTO to encompass transmission facilities outside of New England by giving the owners of such facilities flexible options for participation.*
- *The range of options for participation in the ITC was designed to permit transmission owners, including municipal utilities and other governmental entities that own transmission facilities, the opportunity to participate in ITC in a manner consistent with any legal, financial or other limitations that restrict their ability to sell or transfer control over their transmission assets.*
- *After formation of the ITC, new transmission owners would be permitted to transfer transmission assets to the ITC, to become members in the ITC, LLC and/or to become participants in the ITC.*
- *After formation of the ITC, participants in the ITC may negotiate with the Board of Managers to transfer ownership of its transmission assets for membership in the ITC, LLC, or such other consideration as may be negotiated on arms' length terms.*

Stakeholder-identified Sub-issues Pertaining to Independent Transmission Companies

- See Appendix A-1

III. Market Monitoring and Mitigation

PJM Platform

- The market monitoring unit is responsible for monitoring compliance with the market rules and procedures; actual or potential design flaws in the market rules and procedures and structural problems in the market that may inhibit a robust and competitive market; and the potential of any market participant to exercise undue market power.

- The market monitoring unit has the following enforcement options: engaging in informal discussions; issuing demand letters; recommending changes to governing documents; filing, with Board approval, reports or complaints with regulators or making other appropriate regulatory filings to address design flaws, or other issues; and evaluating additional enforcement mechanisms that may be necessary to assure compliance.
- The market monitoring unit is staffed by qualified PJM employees, and may retain consultants as necessary. The President must ensure that the market monitoring unit has adequate resources to perform its functions.
- The market monitoring unit has available to it all of the market information that is available to PJM. It also may request other information from market participants and may petition FERC for relief if an information request is not answered in a reasonable period of time.
- The market monitoring unit prepares and issues reports on the state of the markets, including identification of problems and recommendations for corrective actions or changes, to the Board, to regulators, and to the public. State commissions can request other reports as well. FERC's 7/12/01 RTO order requires that reports be provided to the Commission at the same time they are provided to the Board.
- The market monitoring plan specifies that the MMU's activities shall be audited in accordance with procedures adopted from time to time by the PJM Board.
- No energy offer price may exceed $1,000/MWh.
- Generator that must be dispatched out of economic merit order in day-ahead market to maintain system reliability as a result of transmission constraints (with certain exceptions) is subject to energy offer price cap. Price cap is based on incremental cost of the generator, plus 10%, or LMP at the generation bus for times when there was no transmission constraint, or agreement of PJM and the generation owner. [FERC recently approved extension of this mitigation to the real-time market.]

<u>Major Differences for New York</u>:

- *In addition to an in-house Market Monitoring Unit (MMU), the NYISO has an Independent Market Advisor that reports to the Board). The Market Advisor provides an external monitoring function to assess the performance of the markets and to consult with the NYISO on market monitoring and mitigation issues.* ***[BP]***
- *The MMU and Market Advisor employ a number of screens and other analyses to identify potential economic and physical withholding of suppliers, manipulative under-bidding of load, or over-production by generators to cause transmission constraints.* ***[BP]***
- *The NYISO has well-defined mitigation authority to address market power concerns:* ***[BP]***
  - *Mitigation applies to energy and ancillary services markets, start-up cost bids, and minimum generation bids.*
  - *MMU mitigation is authorized by FERC when "bright-line" thresholds (described in mitigation plan and posted on website) are met.*

  - *Two-step mitigation screen: conduct (bids exceed specified thresholds above pre-determined reference levels based primarily on generators past bidding) and impact (bids cause market prices to increase above specified thresholds)*
  - *If thresholds exceeded, reference prices can be substituted for bids if the suppliers cannot adequately justify bid. This mitigation process is automated in the Day-Ahead market (AMP).* ***[NOTE: AMP scheduled per FERC order to expire on 10/31/01]***
  - *MMU routinely consults with market participants prior to imposing mitigation measures.*
  - *Mitigation of market power below the specified bright line thresholds requires a § 205 filing by NYISO.*
  - *Limited sanctions for physical withholding and load bidding.*
- *MMU is authorized to mitigate out-of-merit and Supplemental Resource Commitment energy and guarantee bids. In general, out-of-merit units do not set the clearing price.*
- *NYISO has automated day-ahead mitigation procedures for NYC suppliers using New York City localized mitigation measures, and partially automated procedures for NYC units in thunderstorm alerts.* ***[BP]***
- *NYISO may issue Extraordinary corrective Actions ("ECAs") under authority of its Temporary Extraordinary Procedures to correct market design flaws pending the approval and implementation of permanent tariff changes. Such ECAs expire in 90 days.* ***[BP]***
- *[FERC has approved, for implementation this fall, locational reserve pricing including measures to protect against exercise of market power.]*
- *[MMU is formulating monitoring and mitigation procedures applicable to virtual bidding, which will be implemented 11/01/01.]*
- *NYISO currently has a $2.52/Mwh bid cap for 30-minute non-spinning reserve market*
- *In addition to a $1,000/Mwh offer price cap, NYISO has a -$1,000/Mwh offer price cap.*
- *MMU has the right to require data submissions, with specified protections for confidentiality.*
- *MMU is subject to periodic procedural and operational audits.*

<u>Major Differences for New England</u>:

- *ISO-NE Market Monitoring and Mitigation (MMM) group reports directly to CEO, who delegates day-to-day executive management to the VP-Market Operations.* ***[BP]***
- *ISO-NE Board of Directors' Markets Committee has an Independent Market Advisor who, in addition to providing assistance to the Committee, works with the ISO's MMM group on issues related to bid mitigation, market rule changes, and the reporting of market activities.* ***[BP]***
- *Non-Transmission Congestion Monitoring and Mitigation Authorities: ISO-NE has authority under Market Rule 17 to impose remedial measures for the exercise of market power via economic withholding. Monitoring and mitigation plan specifies bid behavior and market impact thresholds for the Energy, AGC and Reserve Markets under which bid is automatically mitigated on the day a bid is received, in absence of adequate explanation by bidder. MMM group has authority to mitigate bids that affect amount of uplift (imposed in connection with*

after-the-fact settlement calculations. For all other non-competitive bid behavior identified by MMM and not covered by automatic mitigation, ISO-NE can file with Commission under Section 205 requesting additional specific monitoring thresholds or mitigation remedies as necessary. ***[BP]***

- *With respect to physical withholding, ISO-NE has authority under Market Rule 13 to impose sanctions to deter noncompliance by Participants that: 1) materially impairs or threatens to impair short-term reliability or the competitiveness or efficiency of the markets, or 2) involves unexcused failure to follow certain ISO instructions or failure to provide to the ISO in certain circumstances accurate and timely information required and requested by the ISO. ISO-NE shall notify the Commission quarterly regarding the identities of the sanctioned parties, the reason for the sanction, and the method by which the amount of the sanction was calculated. [ISO-NE has recently filed with FERC an interim ICAP market proposal. Contained in the proposal is ISO authority to conduct a market power assessment and to settle the market at a predetermined price if the residual market is not workably competitive.]* ***[BP]***
- *Transmission Congestion Monitoring and Mitigation Authorities: Under Market Rule 17, ISO-NE is authorized to apply a competition (structural) screen to detect the exertion of local market power and a price screen to determine a compensation rate for generation run out-of-merit order for congestion. ISO-NE has authority under Market Rule 17 to negotiate mitigation arrangements with generators.*
- *NEPOOL Market Rule 15 provides for price corrections relating to implementation errors and emergency system conditions.*
- *ISO-NE has a $1,000/Mwh offer price cap during Capacity Shortages. This cap expires October 31, 2001.*
- *MMM group publishes monthly and quarterly reports that describe all aspects of market operations including clearing prices with comparisons to other deregulated markets, size of spot market, energy and congestion uplift, load and supply conditions, transmission capacity, and the nature and frequency of mitigation activity. A confidential version of the Quarterly Report is also produced for regulators. ISO-NE meets with state regulators to discuss the quarterly reports.*
- *MMM group reports its activities to the Board's Markets Committee.*
- *MMM group has the right to require data submissions, subject to confidentiality provisions of the NEPOOL Information Policy.*
- *MMM group publishes annual market report that includes an analysis of market performance and developments and details on market operations for the year.*

Stakeholder-identified Sub-issues Pertaining to Market Monitoring and Mitigation

- See Appendix A-1

IV. Recovery of Costs

PJM Platform

- Board approves the annual expense and capital budgets (and any revisions) with advice from Finance Committee.

- Operating and capital costs are billed and collected through Tariff based on accrual accounting expenses.
- Administrative cost recovery structure in the Tariff is unbundled, using formula rates and cost elements from the annual Board-approved budget. Customers are billed based on the actual services each uses; unbundled services include both annual fixed-rate service categories and monthly variable-rate service categories.
- The adequacy of, and compliance with, controls around billing, market settlements, collections, and remittances to members are subject to Statement of Auditing Standards 70 (SAS 70) Type 2 independent audit.
- Financial accounting and treasury functions are subject to periodic internal audit reviews.
- Board must cause to be kept full and accurate books of account, records and supporting documents, which reflect, completely, accurately and in reasonable detail, each transaction of the LLC.
- Annual financial statement audit and quarterly financial statement reviews performed by an independent accounting firm.

Major Differences for New York:

- *NYISO's administrative costs are recovered through Rate Schedule 1 from all New York Control Area (NYCA) loads, through and out wheeling transactions on an energy basis.*
- *Recovery is through a formula rate, updated monthly, on an unbundled basis, solely through the OATT.*
- *Certain Residual Charges are recovered through Schedule 1 which vary on a monthly basis (e.g. – bid production cost guarantee payments).*
- *Start-up costs are recovered through both the OATT and Services Tariff.*
- *New York has long-term commitments which must be honored (e.g. TCC contract obligations extend as long as 5 years).*
- *In New York there are numerous grandfathered agreements which have long-term obligations.*

Major Differences for New England:

- *ISO-NE files its cost recovery tariff under Section 205. ISO-NE works with NEPOOL Budget and Finance Committee in a budget review process. NEPOOL votes on the ISO budget.*
- *ISO-NE collects its annual administrative costs through stated rates in its own tariff, containing three rate schedules. Rate design is somewhat formulaic and the product of a settlement.*

Stakeholder-identified Sub-issues Pertaining to Recovery of Costs

- See Appendix A-1

V. Financing

PJM Platform

- Board is authorized to borrow funds for any purpose, including working capital needs and capital funding needs, with repayment of borrowings billable to customers through the Tariff either as depreciation expense or principal billings.
- Current notes in place for a revolving working capital credit line of up to $15 million and a non-revolving project development credit line of up to $75 million.
- Seven-year unsecured senior notes, in the amount of $110.5 million, executed in December 2000, to acquire ISO infrastructure from transmission owners, bearing interest at a fixed rate of 7.163% and carrying a Moody’s investment grade rating of Aa3.
- Certain debt covenants require written lender approvals prior to any merger or acquisition.

<u>*Major Differences for New York*</u>*:*

- *Long-term debt: There is a five-year amortization period for the recovery of the NYISO’s start-up costs (Initial borrowing: $48.5 million; approximately $ 40 million remaining balance. Repayment obligation through 12/04)*
- *Additional long-term financing of $6.5 million pending PSC approval.*
- *Short term revolver of $ 50 million: used for working capital requirements.*
- *Capital assets: $ 10-15 million*
- *In New York, long-term financing (greater than 1 year) requires approval of the NYPSC.*
- *New York has a target cash reserve level of $50 million, collected from loads, which is used for contingency purposes. This reserve provides for liquidity in the event of an MP default.*
- *Receivables are due 4 days prior to payables in order to ensure full payments are made on time to suppliers.*

<u>*Major Differences for New England:*</u>

- *ISO-NE has entered into lending arrangements to fund capital expenditures ($43 million) and to meet working capital requirements ($15 million). ISO-NE has a Capital Funding Tariff which provides for collections from NEPOOL Participants in the event that prepayment of loans is required.*

Stakeholder-identified Sub-issues Pertaining to Financing

- See Appendix A-1

VI. Credit Policies

PJM Platform

- Membership can be denied or terminated for non-compliance with the established credit policy or non-timely payment of obligations.

- Credit policy is public and is designed to mitigate credit risk to PJM's members. Credit reviews consider member financial viability, historical PJM market activity, analyzes member financial performance, and reviews overall market conditions.
- Members have three days to resolve any breaches of the Operating Agreement before being declared in default.
- Market participant defaults are shared by other members on a weighted basis.
- Members are obligated to pay all billed amounts prior to initiating the dispute resolution process.

Major Differences for New York:

- *New York default provisions are as follows:*
  - *OATT:*
    - *Credit defaults: 60-days notice for termination*
    - *Payment defaults: 30 days to cure; NYISO must file with FERC prior to termination of service*
  - *Services Tariff:*
    - *Credit defaults: 5 business days to cure; afterwards, immediate termination*
    - *Payment defaults: 2 business days to cure; afterwards, immediate termination*
- *New York has a $50 million credit insurance policy to cover major customer defaults.*
- *Market participant defaults are covered by loads through Schedule 1 charges.*

Major Differences for New England:

- *Financial Assurance Policy requires Participants to have investment grade ratings or to post financial assurance (guaranty, surety bond, letter of credit or cash).*
- *Termination of membership only by NEPOOL, with Commission approval.*
- *Separate Billing Dispute Policy for ADR resolution of billing disputes.*
- *Financial consequences of defaults of purchasers and sellers are socialized among the NEPOOL participants.*

Stakeholder-identified Sub-issues Pertaining to Credit Policies

- See Appendix A-1

VII. Information Release

PJM Platform

- PJM operates transparently, maintaining an extensive internet site that provides users access to all operating procedures and all advisory committee proposals and other materials.
- All material non-confidential data, including all offer and bid data after 6 months, are routinely posted on PJM's internet site.

- PJM may not disclose to third parties or other members any information provided by a member or member-applicant and designated by it as confidential under procedures established by PJM. Exceptions are: (i) when member agrees to the disclosure; (ii) when disclosure is compelled by law or judicial or administrative proceedings; and (iii) when FERC requests the confidential information.

  Major Differences for New York:

  - *Mitigation actions are posted (specific market participants are not identified by name).*
  - *New York posts notification and explanations for operational actions.*
  - *NYISO's Code of Conduct governs its treatment of confidential data.*
  - *Pursuant to FPA §201(g), NYISO complies with New York Public Service Commission orders to make certain confidential information available to designated members of NY PSC staff.*
  - *Out-of-merit generation requests are identified by unit name and whether for Statewide or local security.* ***[BP]***
  - *Supplement Resource Commitments are identified by resource type, unit name and whether for Statewide or local security.* ***[BP]***

  Major Differences for New England:

  - *NEPOOL Information Policy generally protects against disclosure of "Confidential Information" of Participants which constitutes trade secrets or commercial or financial information, and has been designated in writing as confidential or proprietary.*
  - *Upon the request of a regulatory agency, other than FERC or its staff, having appropriate jurisdiction and subject to an appropriate confidentiality order, and with advance notice to the Furnishing Participant, the ISO may submit Confidential Information to such agency.*
  - *ISO-NE publishes bid and offer information on its website one hundred eighty (180) days after the day for which the bid and supply offer was in effect, provided that the information is presented in a manner that does not allow for the identification of the specific load or supply asset, its owners, or the name of the entity making the bid or offer, but that allows the tracking of each individual bidder's bids over time.*
  - *Information that is not confidential is generally subject to release unless the ISO believes that release would cause harm to the competitiveness and efficiency of the markets.*

Stakeholder-identified Sub-issues Pertaining to information Release

- See Appendix A-1

Task Two: Establish initial governance and stakeholder structures [except for structures to be determined in Task Four related to ITCs]

Complete: **One month after the Starting Point**[25]

- Form initial corporate entity
- Establish Stakeholder Committees

Task Three: **Commence Implementation**

Complete: **Immediately after Task Two**[26]

- Select and convene Transition Board
- Meet staffing needs
- Stakeholder selection of sectors

Task Four: **Determine basic organizational framework for the RTO**[27]

Complete: **Six months after Task Two**

- Determine legal form(s) of RTO
- Develop role and responsibilities of the RTO board of directors
- Develop role and responsibilities of stakeholder committees
- Develop accountability for RTO board and staff
- Develop initial relationship between RTO and transmission owners and other relevant entities
- Address initial ITC arrangements if any (based on outcome of ITC negotiations)[28]

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[25] Starting point is the Commission order in this proceeding. Certain participants believe that the Commission should elect, as part of the post-mediation process, to "fast-track" resolution of high priority issues. An approach that lays out an Order 636-style process, under the auspices of the Commission, to resolve high-priority issues, is proposed. Other participants oppose this approach because they believe that their interests could be unfairly disadvantaged under it.

[26] The post mediation process options, set forth in this Business Plan, provide separate alternatives. This milestone reflects Options 1-G and 3-G. Option 2-G would require at least 1-2 months for this task in order to select additional Transition Board Members not currently on the ISO boards.

[27] This task is the determination of the organizational framework for the permanent RTO. The post mediation process options, set forth in this Business Plan, provide separate alternatives. Options 1-G and 3-G already establish many permanent governance features, and they are not redetermined under this Task. Option 2-G leaves all permanent governance determinations for this task.

[28] This task does not preclude the subsequent formation of additional ITCs or other entities permitted by an open architecture.

- Determine number and scope
- Determine responsibilities
- Determine ITC(s) governance and stakeholder process(es)
- Determine timing of formation

Task Five: **Determine status of market monitor**

Complete: **In parallel timeframe with Tasks Two through Four**

- Define structure/staffing
- Determine scope of responsibilities
- Determine mitigation authority/options

Task Six: **Develop RTO agreements**

Complete: **Three months after Task Four**

Task Seven: **Develop transition plan**

Complete: **One month after Task Six**

- Include plan for addressing:
  - Asset transfers
  - Personnel
  - Technology
  - Pre-existing liabilities and obligations
  - Funding and financing
  - Tax issues

Task Eight: **FERC Filing**

Complete: **One month after Task Six**

- Draft tariff and other necessary documentation
- Stakeholder review of draft tariff sheets and other operative documents, and revise as appropriate in response to such review (iterative process)
- File with FERC
- **Assume three additional months for FERC approval**

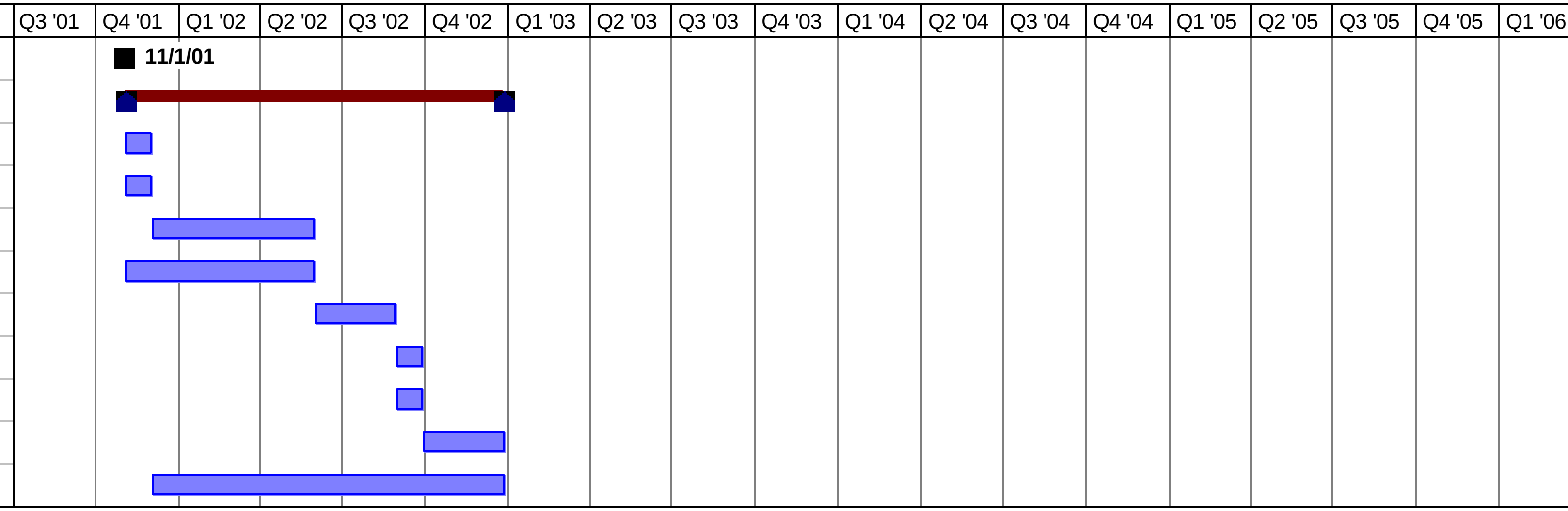
Task Nine: Complete Implementation

Complete: As soon as possible following FERC approval

- Select Permanent Board
- Meet staffing needs

Northeast RTO Milestones for Governance

ID	Task Name
1	**Commission Issues Order on ALJ's Report**
2	**Governance (All Options)**
3	Establish Initial Governance and Stakeholder Structures
4	Commence Implementation
5	Determine Basic Organizational Framework
6	Determine Status of Market Monitor
7	Develop RTO Agreements
8	Develop Transition Plan
9	FERC Filing
10	FERC Approval
11	Complete Implementation



SECTION THREE

RTO Market Design

Task One: **Identify the Basic Elements of the PJM Platform on Market Design and the Differences from the Other ISOs in this Area, including Their Nominated Best Practices**

Complete: **Done**

I. Energy Market, Congestion Management, and Ancillary Services

A. Day-ahead Energy Market

PJM Platform

- The Day-ahead energy market is a Day-ahead forward market that creates the Day-ahead schedule for each hour of the next operating day based on the submitted demand bids, generation offers and transaction schedules.
- The market is based on the concept of Locational Marginal Pricing and it is cleared using least-cost, security constrained unit commitment and dispatch concepts.
- Nodal pricing for generation and load.
- The Day-ahead scheduling process simultaneously optimizes all energy requirements, control area reliability requirements, and reserve obligations in the analysis.
- Generation offer prices are effective for the entire day.
- The Day-ahead energy market supports virtual demand bids and virtual supply offers.
- The Day-ahead energy market supports trading hubs.
- Market supports self-scheduling of generation resources and of bilateral transactions.
- Operating reserve obligations are satisfied through energy market offers.

Major Differences for New York:

- *New York uses a fully automated process to clear separate bid based markets for operating reserves, which are simultaneously optimized with energy and regulation.* **[BP]**
- *New York incorporates penalty factors (losses) in the Day-ahead dispatch and accounts for marginal losses in its LMP calculation.* **[BP]**
- *New York supports self-scheduling in the Day-ahead market through its bid structure.*
- *New York's Day-ahead market structure permits generators to modify their energy and ancillary services bids on an hourly basis.*
- *The LMP for load in New York is zonal based on fixed weighted averages of nodal generation prices across the zone.*
- *New York's Day-ahead market solution includes New York City local reliability rules and their impact on Day-ahead market prices and schedules.*
- *New York's Day-ahead market incorporates a fully automated mechanism for implementation of market mitigation.*

- *New York allocates the cost of local reliability rules to the region that benefits from those rules.*
- *New York's Day-ahead market process provides the forecast load and unit commitment to TO's by 11:00 AM to provide adequate time for them to conduct a local reliability analysis*

<u>Major Differences for New England:</u>

- *New England calculation of LMP includes losses*
- *New England hydro unit dispatch in Real-time may be limited by Day-ahead market commitments.*

B. Real-time Energy Market

PJM Platform

- The Real-time Energy Market is an hourly balancing market.
- The Real-time energy prices are calculated at five-minute intervals based on the actual system operating conditions using the concept of Locational Marginal Pricing.
- The Real-time market price is based on the actual generation response to Real-time least-cost security constrained dispatch instructions.
- The market is an incentive-based market where generators that are following dispatch instructions are eligible to set LMP values and are eligible for revenue recovery of at least their offer data requirements.
- All spot purchases and sales in the balancing market are settled at the hourly-integrated Real-time LMP values.
- Market supports self-scheduling of generation resources and of bilateral transactions.
- Market supports trading hubs.
- Generator station service is netted monthly and generators may remote self-supply station service.
- Market provides for internal bilateral financial transactions.
- Losses are settled as metered demand at marginal prices.
- Operating reserve obligations are satisfied through energy market offers.
- Integrated network of programs facilitates retail access, including data integration and settlements with distribution companies.
- Generator bids are submitted by 6PM Day-ahead for use in Real-time dispatch.

<u>Major Differences for New York</u>:

- *New York has a formal hour-ahead evaluation process (the Balancing Market Evaluation) which adjusts interchange schedules, starts combustion turbines to maintain reserves, adjusts ancillary services schedules and sets prices for hourly ancillary services.* **[BP]**
- *The New York Real-time energy price is based on Real-time least-cost security-constrained dispatch instructions. The New York process is fully automated.* **[BP]**
- *In New York, deviations from Day-ahead generation schedules are settled in the balancing market at the 5 minute Real-time LMP prices.* **[BP]**
- *NYISO does not address netting of station service supply. In general, netting is permitted between generation and load located behind the same delivery point.*

Netting is not permitted between generation and load across delivery points. Remote self-supply of electricity service (commodity) is permitted subject to the respective retail access tariffs.

- *New York settles the Real-time markets based on ex-ante pricing, with deviations from Day-ahead and Hour-ahead schedules settled at the ex-ante Real-time price.*
- *Generators bids are submitted up to 90-minutes prior to the start of the hour.*

<u>Major Differences for New England</u>:

- *New England rules do not specifically address station service.*

C. Financial Transmission Rights

PJM Platform

- A Fixed Transmission Right ("FTR") is a financial instrument that entitles the holder to receive compensation for Transmission Congestion Charges that arise when the transmission grid is congested in the Day-ahead Market.[29]
- An FTR is a financially binding obligation.
- The economic value of an FTR is driven by the Day-ahead LMPs at the source and sink point(s).
- Annual FTR revenue surplusses are allocated to all transmission customers; FTR revenue shortfalls are shared pro rata by all FTR holders.

<u>Major Differences for New York</u>:

- *In New York, TCCs/FTRs are always fully funded. Any excess or shortfall is covered by the TOs where rates are automatically adjusted monthly on a formula basis.* **[BP]**

D. Financial Rights Allocation/Auction

PJM Platform

- There is an annual allocation of FTRs to network service customers based on load ratio shares.
- There is an allocation of FTRs, if available, to firm point-to-point transmission service requests that are granted.
- There is a monthly FTR auction of residual FTR capability and any FTRs offered by current FTR holders into the auction.
- Incremental FTRs are awarded to generators that pay for transmission upgrades.

<u>Major Differences for New York:</u>

- *New York auctions all TCCs/FTRs.* **[BP]**

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[29] New York calls this product a Transmission Congestion Contract ("TCC").

- *TCCs/FTRs may be purchased for 6 months, 1 year and 5 years. Seasonal and monthly auctions are conducted.*
- *New York allocates TCCs/FTRs to market participants paying for transmission upgrades that increase transfer capabilities.* **[BP]**
- *New York is developing an auction process which will simultaneously optimize multiple-duration TCCs.* **[BP]**

Major Differences for New England:

- *New England auctions FTRs and allocates auction revenues to Auction Revenue Rights holders.* **[BP]**

E. Regulation Market

PJM Platform

- The Day-ahead Regulation Market Clearing Price (RMCP) for each hour of the next Operating day is determined by the least cost solution that satisfies the hourly regulation requirements of the control area.
- The RMCP represents a floor price for regulation and it is calculated based on the submitted Regulation offers, the regulation requirements and the Day-ahead energy market results.
- During the operating day, regulation is assigned to the most economically efficient set of units available given the current dispatch and operating constraints.
- Compensation for regulation is the higher of RMCP or the offer price plus Real-time opportunity cost.

Major Differences for New York:

- *The New York Day-ahead regulation market is included in the Day-ahead optimization.* **[BP]**
- *New York does not reassign regulation requirements outside of the hourly evaluation process.*

F. Reactive Services

PJM Platform

- All transmission service loads pay for reactive service based on a load ratio share of the reactive requirement.
- The payment covers the total reactive power revenue requirements, as approved by the Commission, of the generation in the control area.

Major Differences for New York:

- *New York loads pay their share of statewide reactive services costs based upon their proportional energy requirements.*
- *New York payments for reactive services are based on demonstrated generator VAR capabilities.* **[BP]**

<u>Major Differences for New England:</u>

- *New England generators are paid for routine power support according to a prescribed formula contained in the Tariff.* **[BP]**
- *In New England, compensation to generators providing this service is based on four components; the first component is "fixed," and the other three components are "variable": (1) Capacity Cost component for the capability of a Qualified Generator to deliver VARs to the system; (2) Lost Opportunity Cost component for hydro and pumped storage generating units motoring at the request of the ISO (this component for synchronous condensers and static controlled VAR regulators is currently set to zero); (4) Cost of Energy Produced component for generating units (hydro, pumped storage and thermal) brought on-line by the ISO for the purpose of providing this service.*

G. Operating Reserves

PJM Platform

- Operating reserve obligations, including locational requirements, are satisfied through energy market offers rather than through a separate market.
- Synchronous-condensing equipment can provide operating reserves.
- PJM pays lost opportunity costs if PJM requests a unit to operate out of merit order for operating reserves.

<u>Major Differences for New York:</u>

- *New York administers Day-ahead and Real-time bid based markets for 10 minute spinning, 10 minute non-spinning and 30 minute non-spinning reserves which recognize locational requirements.* **[BP]**
- *New York provides compensation for lost opportunity costs for participants in the 10 minute reserves markets.*

<u>Major Differences for New England:</u>

- *In New England, the Standard Market Design (which PJM also intends to adopt) will include a spinning reserve market.* **[BP]**
- *Some demand response resources qualify for payments based on operating reserve prices.*

H. Control Areas

PJM Platform

- The market design may be extended over multiple control areas. Currently, the market design is approved to overlay the two control areas of PJM and PJM West.
- A single Day-ahead energy market (as described above) is approved to operate across the combined PJM and PJM West region developed as described above. A single Real-time energy market is approved to operate across the combined PJM and PJM West region, with a single dispatch over the two control areas of the combined region developed as described above.

- The regional dispatch dynamically sets tie schedules between the control areas.
- There is a separate regulation market (with the same rules) for each control area.
- Reserve objectives are met separately for each control area; emergency load-shedding is control area specific.

I. Parallel Path Flows

PJM Platform

- Parallel ("loop") flows are internalized with a single market in the combined PJM and PJM West region.

J. Demand Response

PJM Platform

- Allowance for demand bids in the Day-ahead market facilitates demand response.
- Real-time price signals facilitate demand response during the operating day.
- There are additional experimental load response programs in effect which allow economic and emergency demand response.

Major Differences for New York:

- *New York's Day-Ahead Demand Response Program ("DADRP") is fully automated in the Day-ahead market and settlement process and permits the submission of demand-side bid curves analogous to generator bid curves.* **[BP]**
- *New York's economic demand response program pays LMP directly to participants without deducting retail rates.*
- *New York participants can participate in more than one market (e.g., emergency and ICAP markets.)*
- *New York's Emergency Demand Response Program ("EDRP") is voluntary and includes minimum payment provisions to ensure that loads that participate will recover a base amount to justify their response.*
- *New York's EDRP customers can also participate as ICAP supplier and receive compensation under both programs.*

K. Generation Information System

PJM Platform

- PJM is developing a Generation Attributes Tracking System ("GATS"). (The GATS is an attribute tracking system that follows attributes through the contract path from the generator to the retail supplier.)

Major Differences for New England:

- *New England is developing a Generation Information System ("GIS"). (The GIS is a generation information database and certificate system containing hourly generation information that accounts for certain attributes of energy consumed within the control area and exported outside of the control area.)* **[BP]**

L. Black Start Service

PJM Platform

- No separate compensation for black start service provided by generators.

  Major Differences for New York:

  - *In New York, compensation is provided for provision of black start service.*

  Major Differences for New England:

  - *In New England, eligible generators are compensated under a schedule to the NEPOOL tariff for their costs of providing system restoration and planning services. All transmission customers pay for these services.* ***[BP]***

M. Stakeholder-identified Sub-issues Pertaining to Energy Market, Congestion Management, and Ancillary Services

- See Appendix A-2

II. Generation Adequacy (Capacity) Issues

A. Capacity Adequacy Planning Process

PJM Platform

- Requires generation resources in excess of forecasted peak load, to maintain the long term adequacy and security of the system in the event of higher than forecast system loads or unanticipated outages of generating resources.
- Reserve level based on the regional requirement of a loss-of-load expectation of one day in ten years.
- Reserve requirements are set two-years in advance of the planning period.
- "Capacity Benefit Margin" (ability of RTO to depend on assistance from outside resources) is set aside as a reliability benefit that accrues to all load serving entities. The transmission capability associated with this benefit may be used for non-firm transmission service, but not for firm service.
- Reserve level is based on the assumption of collective "deliverability" of generation to load within PJM. Load pockets can be provided energy from the aggregate of PJM generation; and generation capacity is not "bottled."
- As a result of the "deliverability" planning assumption, any load may use any qualified resource to satisfy its capacity obligations. Deliverability does not ensure that the energy from a specific resource is deliverable to a specific load.
- "Unforced Capacity" obligations (based on resources whose installed capacity has been discounted to account for actual forced outage rates) are imposed on load serving entities to obtain generating resources seasonally to meet their share of the need for capacity for the system.
- Capacity obligations and unit ratings are based on summer values.
- Load management programs reduce capacity obligations.

- Reserve requirement analysis is forward looking and is typically done for a future five (5) year period. This analysis is performed every year (annually) to reflect the most recent forecasts and input parameters.

  Major Differences for New York:

  - *New York has locational requirements for capacity in New York City and Long Island.* **[BP]**
  - *New York's proposed UCAP market will allow obligations to be met on a monthly basis.* **[BP]**
  - *Energy-only providers (non-ICAP) units are counted for meeting IRM (Installed Reserve Margin) in New York.*
  - *NYRSC has the responsibility to determine the statewide installed reserve requirement.*
  - *NYISO determines the allocation of the statewide installed reserve requirement to LSE's, including any locational requirements.*
  - *New York currently has an annual ICAP requirement with a six (6) month obligation procurement period.*
  - *New York uses seasonal (summer and winter) capacity values.* **[BP]**
  - *Load management programs either reduce capacity obligations or may participate directly in NYISO ICAP market.* **[BP]**
  - *New York does not have a deliverability requirement other than its locational reserves requirements.*
  - *All NYCA generation is considered in determination of capacity requirements.*

  Major Differences for New England:

  - *New England does not have a deliverability requirement.*
  - *New England plans to the one-day-in-ten-years generation adequacy standard. This requires generation levels above the level of peak loads.*
  - *ISO New England includes tie benefits from external contracts in the calculation of generation adequacy.*
  - *The generation adequacy standard assumes that all resources can meet all load.*
  - *New England has no deliverability standard. It has a minimum interconnection standard.*
  - *All generation resources can be used to meet all load obligations.*

B. Capacity Market Structure

PJM Platform

- Load serving entities can satisfy capacity obligations through owned resources, bilateral contract, or capacity credits.
- Portions of resources can be designated to satisfy capacity obligations.
- Non-recallable external resources, with firm transmission service, can satisfy capacity obligations.
- Capacity credits are the accounting value (or credit) derived from specific generating capacity resources or active load management resources that may be used to satisfy capacity obligations.

- Capacity credits may be purchased bilaterally from generating resource owners or other holders of credits, or may be purchased through regular auctions--monthly, multi-month, and Day-ahead.
- Load serving entities may request FTRs associated with Network Transmission Service for specific generating capacity resources that they have secured through ownership or bilateral contract. There are no FTRs associated with capacity credits obtained through the auctions.
- Penalties are imposed for failure to meet Unforced Capacity obligations.
- Energy from designated capacity resources can be sold externally, subject to recall during emergencies.
- Capacity resources must bid into the market each day (if not already committed via an internal bilateral transaction).
- Capacity in excess of seasonal obligations can be delisted daily.

Major Differences for New York:

- *New York does not allow resources to withdraw from the capacity market on a daily basis.*
- *NYISO administers a periodic ICAP auction for both suppliers and LSE's and does not utilize "capacity credits."*
- *There are no TCC rights associated with New York's ICAP process. TCC's are available through a separate auction open to all market participants.*
- *New York's "special case resource" provisions allow load to participate in the NYISO ICAP market.*
- *Intermittent and renewable resources can participate in the NYISO ICAP market but are granted exemptions from certain supplier obligations.* ***[BP]***
- *ICAP deficiency penalties vary by location.*
- *There are mandatory bid and price caps for certain NYC ICAP suppliers.* **[BP]**

Major Differences for New England:

- *New England does not have a capacity market. It has a capacity requirement based on meeting the one-day-in-ten-years system reliability criteria.*
- *Load serving entities can satisfy capacity obligations through owned resources or bilateral contracts.*
- *Allocation of the requirement is based on actual monthly peak load.*
- *The deficiency charge in New England is $4.87/kw-mo.*
- *All resources in New England are in the capacity market.*
- *All capacity in New England can be recalled to serve New England load in a capacity shortage in New England.*
- *Rule changes are pending to allow New England capacity to provide capacity to New York.*
- *External resources that have transmission service and bid firm energy into the New England energy market can provide capacity in New England.*
- *There is no adjustment to capacity resources for generator availability but resources that are unavailable for more than five months lose capacity credits.*
- *Ratings and requirements are varied seasonally.*
- *All resources are required to bid into markets.*

- *[New England anticipates converting current hourly offline reserve markets to an offline capacity product.]*
- *New England does not have a deliverability requirement.*
- *New England does not use Unforced Capacity.*
- *New England capacity requirement is determined retroactively.*
- *New England does not have ISO-operated spot capacity markets.*

C. PJM West

- Employs “Available Capacity” Obligations that are compatible with “Unforced Capacity” obligations.
- Available Capacity takes into account planned and unplanned outages to reflect only capacity that is actually available for operations.
- Penalties are imposed for failure to satisfy Available Capacity obligations, with options to mitigate or avoid penalties.
- “Deliverability” planning assumption is applied to the entire PJM/PJM West area. Consequently, an individual generating resource within either PJM or PJM West can be used to satisfy the capacity obligations of any PJM or PJM West load serving entity.
- PJM West load serving entities may use the same mechanisms as PJM load serving entities (resources owned or contracted for, or credits obtained through contracts or markets) to satisfy capacity obligations.
- All load serving entities in PJM or PJM West can participate in the entire range of capacity credit markets for the capacity credit product associated with their particular form of obligation.

D. Stakeholder-identified Sub-issues Pertaining to Generation Adequacy (Capacity) Issues

- See Appendix A-2

Milestones for Market Design—Option 1-M[30]

Task Two: Produce RTO Market Design for the Northeast[31]

Complete: Three Months after the Starting Point[32]

- Identify and agree on best practices to enhance PJM platform and deal with local issues.[33]
  - Address best practices for local reliability and local market power issues
  - Address ISO-nominated best practices identified in this Business Plan in each sub-area:
    - Day-ahead Energy Market
    - Real-time Energy Market
    - Financial Transmission Rights
    - Regulation Market
    - Reactive Services
    - Operating Reserves
    - Demand Response Program
    - Generation Information System
    - Black Start Service
    - Capacity Adequacy Planning
    - Capacity Market
  - Address any other identified best practices in above sub-areas

Task Three: Produce Detailed Market Specifications

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30 The attached White Paper entitled "The Option 1M Implementation Plan" (Appendix B) is indicative of how the milestones for Market Design in Option 1M can best be achieved. Among other things, this approach assumes the use of "best implementation practices" in the RTO establishment process, including the adoption of the "management executes an approved plan" approach. It is envisioned that the best practices nominated by ISO New England and the New York ISO will be evaluated as part of the RTO formation process and be considered for inclusion in the PJM platform in advance of the commencement of a single Northeastern market.

31 The New York ISO proposes an additional parallel task, "Identify Interim Steps for Moving Toward a Common Market," concluding ten months after Task Two. This task consists of the following consecutive sub-tasks: Develop Detailed Interim Specifications, two months; Finalize Interim Tariff Specifications and File with FERC, two months; Interim Systems Implementation, three months; and Interim Market Implementation, three months.

32 Starting point is the Commission order in this proceeding and implementation of effective post-mediation process.

33 This step is not sufficient for tariff development or detailed software design

Complete: **Four months after Task Two**

- Draft business rules based on resolution of best practices and on market design concepts and elements established through Task Two
- Stakeholder review of draft business rules and revise as appropriate in response to such review (iterative process)

Task Four: **Develop Implementation Plan**

Complete: **Two months after Task Three**

- Prepare preliminary budget
- Prepare funding plan
- Develop transition schedule

Task Five: **FERC Filing**

Complete: **Two months after Task Four**

- Draft tariff and other necessary documentation[34]
- Stakeholder review of draft tariff sheets and other operative documents, and revise as appropriate in response to such review (iterative process)
- File with FERC
- **Assume three additional months for FERC approval**

Task Six: **Systems Implementation**

Complete: **Eighteen to thirty months[35] after FERC approval**

- Develop design specifications
- Conduct procurement efforts
- Develop software applications
- Conduct systems integration

[34] Option 1-M milestones would be married to the other timelines, including transmission tariff and governance.

[35] PJM and New England believe that this schedule can be shortened if New England implements the Standard Market Design ("SMD") prior to the start of a single RTO market. New York is currently evaluating the SMD. The three ISOs believe that the schedule can be further shortened if all three markets could move toward a similar market design based on the PJM platform prior to the implementation of a single market.

- Test and deploy new systems

Task Seven: Market Implementation

Complete: Six months after Task Six

- Conduct market trials and market participant training
- Conduct transition from three markets to single market, including data conversion
- Commence "live" markets

SUPPORTERS OF OPTION 1-M

Capstone Turbine
City and Towns of Hagerstown, Thurmont, and
Williamsport, MD and Front Royal, VA.
IMO
ISO-New England
Jamestown, New York
Municipal Electric Utilities Association
of New York State
New York ISO
Vermont Electric Power Company

Milestones for Market Design - Option 2-M[36]

Task One: Same as above

Task Two: Produce RTO Market Design for the Northeast

Complete: Three Months after the Starting Point[37]

- Identify and agree on best practices to enhance PJM platform and deal with local issues by applying Best Practices Considerations.[38]
  - Address best practices for local reliability and local market power issues
  - Address ISO-nominated best practices identified in this Business Plan in each sub-area:
    - Day-ahead Energy Market
    - Real-time Energy Market
    - Financial Transmission Rights
    - Regulation Market
    - Reactive Services
    - Operating Reserves
    - Demand Response Program
    - Generation Information System
    - Black Start Service
    - Capacity Adequacy Planning
    - Capacity Market
  - Address any other identified best practices in above sub-areas
  - To determine the viability of Best Practices market design resulting from this or any other option, the following tasks should be performed:
    - Identify the critical path technological challenges to adapt the PJM Platform to solve for NY and NE operational requirements and critical commercial practices.
    - Identify whether PJM cannot solve for any of these requirements or practices upon market start-up.
    - For each of these requirements or practices, identify all significant reliability and financial impacts.

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36 Appendix C, "Integrated Northeast Market Concept," is indicative of how the milestones for Market Design in this Option 2-M can be achieved. Among other things, Option 2-M provides for technology issues to be resolved and best practices to be incorporated into a common design prior to the start of implementation. Option 2-M also provides for phased implementation of certain common markets.

37 Starting point is November 1, 2001.

38 This step is not sufficient for tariff development or detailed software design

- In performing the foregoing tasks, address the following items:
    - GT and hydro dispatch
    - Possible impacts on interface limits associated with manual operator interventions or solving for individual transmission contingencies versus interface limits.
    - Handling of operating reserves and other ancillary services
    - Treatment of local reliability rules and market power mitigation in Day-Ahead unit commitment and real-time dispatch software
    - Operation of Con Edison underground system
    - Treatment and optimization of PARs
- For each item, consider major cost factors, including costs associated with software development and modification, development or modification of state estimators, metering and communication systems

The proponents of Option "B" strongly advocate advancement of these action items, commencing immediately, and irrespective of which Option is ultimately selected. These tasks should be the subject of periodic reports to the Commission and subject to professional facilitation by a neutral third party. The facilitator should have access to an IT consultant to assist in the process.

Task Three: Develop and Implement Common Market Elements

Complete: Commence two months after the start date and complete by December 1, 2002

- Identify Interim steps to move toward a common market
- Develop detailed interim specifications
- Finalize interim tariff specifications and file with FERC
- Interim systems implementation
- Interim market implementation

Task Four: Produce Detailed Market Specifications

Complete: Four months after Task Two

- Draft business rules based on resolution of best practices and on market design concepts and elements established through Task Two
- Stakeholder review of draft business rules and revise as appropriate in response to such review (iterative process)

Task Five: Develop Implementation Plan

Complete: Two months after Task Four

- Prepare preliminary budget
- Prepare funding plan
- Develop transition schedule

Task Six: **FERC Filing**

Complete: **Two months after Task Five**

- Draft tariff and other necessary documentation[39]
- Stakeholder review of draft tariff sheets and other operative documents, and revise as appropriate in response to such review (iterative process)
- File with FERC
- **Assume three additional months for FERC approval**

Task Seven: **Systems Implementation**

Complete: **Eighteen months after FERC Filing**

- Develop design specifications
- Conduct procurement efforts
- Develop software applications
- Conduct systems integration
- Test and deploy new systems

Task Eight: **Market Implementation**

Complete: **Six months after Task Seven**

- Conduct market trials and market participant training
- Conduct transition from three markets to single market, including data conversion
- Commence "live" markets

[39] Option 2-M milestones would be married to the other timelines, including transmission tariff and governance. The One RTO Coalition believes that, in order to avoid cost shifting and potential inconsistencies with retail rate freezes presently in effect, existing zonal transmission rates should be allowed to remain in effect for a transition period extending through 2004; that, in order to maintain revenue neutrality in the elimination of pancaked rates, mechanisms should be in place to avoid loss of point-to-point revenues for transmission owners for a transition period extending through 2004, without materially impacting external seams costs and while respecting retail rate freezes presently in effect; and that the RTO should be structured so as to provide sufficient flexibility to accommodate varied transmission ownership arrangements, including one or more ITCs, individual ownership, merchant transmission, or any other type of transmission arrangements.

SUPPORTERS OF OPTION 2-M

Central Hudson Gas & Electric Corporation
Central Maine Power
Consolidated Edison Company of New York, Inc.
Con Edison Energy
Con Edison Solutions
IMO
Jersey Central Power and Light
Long Island Power Authority
Metropolitan Edison
New York State Electric & Gas Corporation
Niagara Mohawk Power Corporation
Orange and Rockland Utilities, Inc.
Penelec
Power Authority of the State of New York
Rochester Gas and Electric Corporation

Milestones for Market Design - Option 3-M[40]

Task One: **Determine Extent of Supplementation of PJM Platform By ISO-nominated Best Practices**

Complete: **Three months after the starting point**[41]

Task Two: **Develop Implementation Plan**

Complete: **Concurrent with Task One**

- Prepare preliminary budget
- Prepare funding plan
- Develop transition schedule

Task Three: **FERC Filing**

Complete: **Six months after Task Two**

- Draft tariff and other necessary documentation[42]

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40 The attachment, "Regional Networked Market Concept" (Appendix D), is indicative of how the milestones for Market Design in this Option 3-M can be achieved. Among other things, this approach assumes use of the existing EMS and Real-time dispatch software within each control area for initial implementation. It is envisioned that in the ensuing process the detailed design (see Figure 4 in Appendix D) will incorporate resolution of additional issues that are consistent with achieving this schedule.

41 The starting point is the Commission order in this proceeding.

42 Option 3-M milestones would be married to the other timelines, including transmission tariff and governance. The One RTO Coalition believes that, in order to avoid cost shifting and potential inconsistencies with retail rate freezes presently in effect, existing zonal transmission rates should be allowed to remain in effect for a transition period extending through 2004; that, in order to maintain revenue neutrality in the elimination of pancaked rates, mechanisms should be in place to avoid loss of point-to-point revenues for transmission owners for a transition period extending through 2004, without materially impacting external seams costs and while respecting retail rate freezes presently in effect; and that the RTO should be structured so as to provide sufficient flexibility to accommodate varied transmission ownership arrangements, including one or more ITCs, individual ownership, merchant transmission, or any other type of transmission arrangements.

- Stakeholder review of draft tariff sheets and other operative documents, and revise as appropriate in response to such review (iterative process)
- File with FERC
- **Assume three additional months for FERC approval**

Task Four: **Systems Implementation**

Complete: **Eighteen months after the starting point**

- Develop design specifications
- Conduct procurement efforts
- Develop software applications
- Conduct systems integration
- Test and deploy new systems

Task Five: **Market Implementation**

Complete: **Six months after Task Four**[43]

- Conduct market trials and market participant training
- Conduct transition from three markets to single market, including data conversion
- Commence "live" markets

Deliverables:

Option 3-M (under the Regional Networked Market model) is designed to achieve implementation of the following functions under the schedule of these milestones:

- Single Day-ahead Energy Market
- Single Real-time Energy Market
- Single Financial Transmission Rights Product/Market
- Single OASIS System
- Single Transaction Management System
- Single Market Information System
- Single Settlements and Billing System
- Four Regulation Markets (with common rules)
- Four separate Operating Reserve Areas
- Black start and reactive compensation (based on existing practices)

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43 Although a supporter of Option 3-M, Enron Power Marketing, Inc. believes the Regional Networked Market can and must be implemented no later than December 2002.

- Under the RNM concept, ICAP markets initially could be either separate, based on existing designs, or a new region-wide market, without affecting the milestone schedule.

RNM also can accommodate 10-minute operating reserve markets (both spinning and non-spinning) within one year after the energy market start-up, and subsequent implementation of a 30-minute operating reserve market.

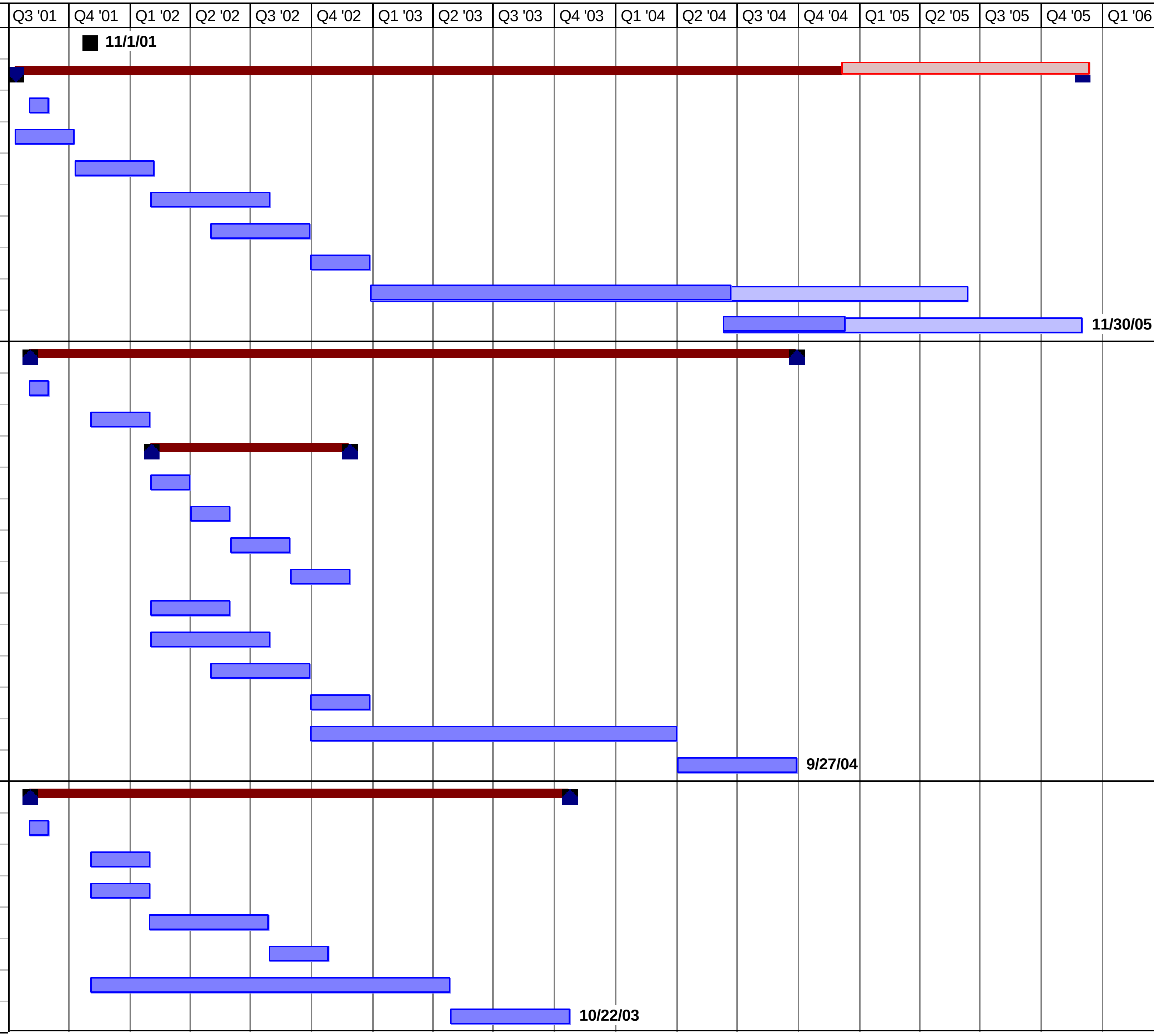
SUPPORTERS OF OPTION 3-M

AES NewEnergy
AES New York LLC
Allegheny Electric Cooperative, Inc.
Allegheny Power System Operating Companies (PJM West)
American National Power
American Wind Energy Association
Aquila Inc.
Atlantic City Electric Company
Baltimore Gas & Electric
Braintree Electric Light Department
Calpine
Cape Wind Associates
Commonwealth Chesapeake Company, LLC
Constellation Energy Group
Constellation Power Source
Delaware Electric Municipal Corporation
Delmarva Power & Light Company
Distributed Power Coalition of America
Dominion Energy
Duke Energy North America
The E Cubed Company, LLC
Edison Mission Energy
Edison Mission Marketing & Trading
El Paso Merchant Energy
Energy Management, Inc.
Enron Power Marketing, Inc.
Entergy Nuclear Northeast
Exelon Generation Company, LLC
FPL Energy
HQ Energy Services (U.S.) Inc.
Joint Supporters
Keyspan-Ravenswood, Inc.
Maryland Office of the People's Counsel
Mid-Atlantic Area Council
Mid-Atlantic Power Supply Association
Mirant Americas, Inc.
Mirant Americas Energy Marketing, LP
Morgan Stanley Capital Group Inc.
NEPOOL Industrial Customer Coalition
New England Renewable Power Producers Association
New Jersey Division of Ratepayer Advocate

The NRG Companies
Old Dominion Electric Cooperative
Orion Power
Pace Energy Project
PECO Energy Company
Pennsylvania Office of Consumer Advocate
Pennsylvania Public Utilities Commission
PG&E National Energy Group
PJM Industrial Customer Coalition
PJM Interconnection, L.L.C.
Potomac Electric Power Company
Power Development Company
PPL EnergyPlus, LLC
PPL Electric Utilities Corporation
Project for Sustainable FERC Energy Policy
PSEG Power, LLC
PSEG Energy Resources & Trade, LLC
Public Service Electric & Gas Company
Reading Municipal Light Department
Reliant Energy Northeast Generation, Inc.
Select Energy Inc.
Sithe New England Holdings LLC
Sithe Power Marketing LP
Strategic Energy
Taunton Municipal Light Department
TransEnergie
TransEnergie U.S., Ltd.
TXU Energy Trading
UGI Utilities, Inc.
The Williams Companies, Inc.
Wisvest-Connecticut, LLC

Northeast RTO Milestones for Market Design

ID	Task Name
1	**Commission Issues Order on ALJ's Report**
2	**Market Design (Option 1-M)**
3	Describe Platform and Differences
4	Produce RTO Market Design for Northeast (Note 1.)
5	Produce Detailed Market Specifications
6	Develop Implementation Plan
7	Finalize Tariff and File with the FERC
8	FERC Approval of Tariff
9	Systems Implementation
10	Market Implementation
11	**Market Design (Option 2-M)**
12	Describe Platform and Differences
13	Produce RTO Market Design for Northeast
14	**Identify Interim Steps for Moving to a Common Market**
15	Developed detailed interim specifications
16	Finalize interim tariff and file with FERC
17	Interim systems implementation
18	Interim Market Implementaiton
19	Produce Detailed Market Specifications
20	Develop Implementation Plan
21	Finalize Tariff and File with the FERC
22	FERC Approval of Tariff
23	Systems Implementation
24	Market Implementation
25	**Market Design (Option 3-M)**
26	Describe Platform and Differences
27	Supplement PJM Platform with BPs
28	Develop Implementation Plan
29	Finalize Tariff and File with the FERC
30	FERC Approval of Tariff
31	Systems Implementation
32	Market Implementation



SECTION FOUR

RTO Operations

Task One: Identify the Basic Elements of the PJM Platform on Operations and the Differences from the Other ISOs in this Area, Including Their Nominated Best Practices

Complete: Done

I. Generation Scheduling

PJM Platform

- Generators have the option of self scheduling, offering generation into the day-ahead market, or offering generation into the real-time market.
- Designated capacity resources must submit day-ahead offers or self-schedule bilateral transactions.
- Generators can self-schedule anytime with 20 minutes notice; self-schedule generators are "price takers."
- Generation offers selected in the day-ahead market are financially bound to their day-ahead scheduled price and quantity. However, there are no requirements for the generator to actually run in the real-time market, since all imbalances are cleared at the real-time price.
- Generators not selected in the day-ahead market can re-bid for the real-time period if desired.
- PJM performs a reliability-based unit commitment after the day-ahead market is settled to ensure adequate generation and transmission system reliability.
- PJM can start or schedule generators at any time for reliability.
- Reliability commitment is performed after day-ahead prices are posted and this does not impact prices.

Major Differences for New York:

- *New York generators can self-schedule any hour with 90 minutes notice.*
- *The New York generator self-scheduling process is a fully automated bid-based process.* ***[BP]***
- *New York generators may submit bids for energy, minimum generation costs, and ancillary services that may vary for each hour of the DAM and HAM, which accommodates the scheduling needs of all generation and demand response technologies.* ***[BP]***
- *New York performs a reliability based unit commitment to meet forecast load and export requirements, that includes New York City Local Reliability Rules and FERC-approved New York City market mitigation rules, as part of the security constrained unit commitment solution for the DAM posted at 11:00 AM of the prior day.* ***[BP]***
- *The New York SCUC process will commit generation resources in the DAM sufficient to support ISO load forecast requirements.*

- *In New York, intermittent capacity resources are exempt from the requirement to bid into the NYISO's DAM.*
- *In New York, the reliability commitment is performed as part of the DAM process and may impact prices.*

Major Differences for New England:

NOTE: ISO New England has proposed to migrate to the PJM Platform. Accordingly, New England operational differences from PJM in the future would be limited throughout to differences necessary to accommodate: (1) the nature of New England resources (including renewable resources) and their ramping capability; (2) the location of New England on the grid; and (3) the contrast between the NPCC 30-minute reserve requirement and the MAAC 30-minute reserve objective.

Stakeholder-identified Sub-issues Pertaining to Generation Scheduling

- See Appendix A-3.

II. Transaction Scheduling

PJM Platform

- Internal financial transactions (schedules) can be submitted to settlements anytime up to noon the day after.
- External transactions can self-schedule anytime up to twenty minutes before the start or change of schedule.
- External transactions can either self-schedule (price taker) or provide a rate at which to be dispatched similar to internal generators.
- External transactions can schedule every quarter hour (i.e. :00, :15, :30, :45).
- External transactions can fully participate in the day-ahead market through virtual bidding as a generator or load, bidding an "up to" congestion cost the party is willing to pay, or self-scheduling a fixed amount.
- Net control-area transaction schedule changes totaling up to 500 Mw each quarter-hour are permitted on a first-come, first-served basis.

Major Differences for New York:

- *New York allows external transactions to be scheduled hourly.*
- *New York allows external transactions to "self schedule" through a bid-based economic evaluation conducted 90 minutes ahead of real time (BME).*
- *New York requires all external transactions to provide a bid.* ***[BP]***
- *New York allows net control-area transaction changes up to 700 MW hourly based on competitive economic order.*
- *[New York plans to implement virtual bidding in November 2001.]*
- *In New York, transaction schedules are confirmed when day-ahead schedules are posted. Such schedules are still subject to the hourly operations "check-out" process.*

<u>Major Differences for New England</u>:

NOTE: ISO New England has proposed to migrate to the PJM Platform. Accordingly, New England operational differences from PJM in the future would be limited throughout to differences necessary to accommodate: (1) the nature of New England resources (including renewable resources) and their ramping capability; (2) the location of New England on the grid; and (3) the contrast between the NPCC 30-minute reserve requirement and the MAAC 30-minute reserve objective.

Stakeholder-identified Sub-issues Pertaining to Transaction Scheduling

- See Appendix A-3.

III. Generation Dispatch

PJM Platform

- Generation is dispatched using a centralized security constrained dispatch based on generation offers received.
- PJM uses a simultaneous optimization as an advisory dispatch; generation shifts are primarily determined by the operators based on actual conditions and responses of units.
- Generation can switch from pool-scheduled to self-scheduled (and vice-versa) with twenty minutes notice.
- Units are monitored and tracked for performance; units following dispatch can set locational prices based on their offers, and units choosing not to follow dispatch (self-schedule) are price takers.
- PJM has the ability to recall capacity resources during an emergency.

<u>Major Differences for New York</u>:

- *New York uses a fully automated security constrained dispatch optimization to control New York Control Area generator dispatch, including generator shifts required to simultaneously solve all active transmission constraints, while taking account of incremental losses on injections at each generation source.* ***[BP]***
- *The New York dispatch software sends distinct dispatch signals to all generators for each dispatch interval.*
- *Generation capacity scheduled to provide 10 minute reserves is not available for dispatch by SCD.*
- *New York uses its security constrained dispatch optimization to start and dispatch 10-minute gas turbines that may set LMP.* ***[BP]***
- *New York uses its BME to commit 30-minute gas turbines.*
- *New York incorporates self-scheduled generation in its hourly scheduling process.*

<u>*Major Differences for New England*</u>:

NOTE: ISO New England has proposed to migrate to the PJM Platform. Accordingly, New England operational differences from PJM in the future would be limited throughout to differences necessary to accommodate: (1) the nature of New England resources (including renewable resources) and their ramping capability; (2) the location of New England on the grid; and (3) the contrast between the NPCC 30-minute reserve requirement and the MAAC 30-minute reserve objective.

- *ISO New England would implement the PJM platform with the security constrained dispatch of generators performed through the Electronic Dispatch infrastructure.*

Stakeholder-identified Sub-issues Pertaining to Generation Dispatch

- See Appendix A-3.

IV. Transmission Operations

PJM Platform

- PJM is the security coordinator.
- PJM monitors and controls all designated transmission facilities (all high voltage, and lower voltages designated by transmission owners).
- PJM is responsible for the day-ahead analysis and scheduling of transmission outages as well as the real-time analysis.
- PJM coordinates daily with the transmission owners and provides load and outage data to them for their reliability analyses. Where authorized by the affected generator, data on actual output, prescheduled expected output, and planned outages for generators are also provided to the transmission owners.
- PJM has an automated security analysis that monitors all designated facilities under normal and "single-contingency" conditions every 5 minutes. Automated voltage stability analysis is performed every 15 minutes.
- Reactive transfer limits are automatically calculated based on AC voltage analysis and updated in real-time.
- PJM operates considering a number of different operating conditions, including special purpose relays, emergency conditions, etc.

<u>*Major Differences for New York*</u>:

- *New York coordinates daily with the Transmission Operators and provides load, outage, expected generator output, and power flow solutions for each hour of the Day-Ahead Market by 11:00 AM of the prior operating day as required for local transmission owner reliability evaluation.* ***[BP]***
- *New York's security constrained dispatch optimization includes normal, single and multiple contingency analysis, including PSC mandated thunderstorm watch contingencies, every 5 minutes.* ***[BP]***
- *New York optimizes phase-angle regulator schedules for all designated facilities in its Day-Ahead Market solution.* ***[BP]***
- *New York has a Back-up Dispatch System (BDS), which differs from PJM's.*

<u>Major Differences for New England</u>:

NOTE: ISO New England has proposed to migrate to the PJM Platform. Accordingly, New England operational differences from PJM in the future would be limited throughout to differences necessary to accommodate: (1) the nature of New England resources (including renewable resources) and their ramping capability; (2) the location of New England on the grid; and (3) the contrast between the NPCC 30-minute reserve requirement and the MAAC 30-minute reserve objective.

- *ISO New England is the security coordinator for the NEPOOL Control Area and for the Maritimes.*
- *ISO New England operates the transmission system to meet NPCC and NERC standards and criteria. Specifically, ISO New England also considers different operating conditions including both pre- and post- first contingency conditions, special purpose relays, emergency conditions, etc.*
- *ISO New England has an automated security analysis that monitors all designated facilities under normal and "single contingency" conditions at least once every 7 minutes. Voltage and stability limits are monitored at least once every 3 minutes. The Operator has the capability to initiate these programs at anytime within the normal periodicity.*
- *Reactive transfer limits are developed off-line by ISO New England support staff and are monitored in real-time.*

Stakeholder-identified Sub-issues Pertaining to Transmission Operations

- See Appendix A-3.

V. Control Area Operations

PJM Platform

- PJM operates to and maintains a 10-minute synchronized operating reserve, a 10-minute unsynchronized operating reserve, and a 30-minute off-line reserve objective.
- PJM uses generator offers into the energy market to provide additional reserves if necessary.
- PJM is responsible for forecasting control area load.
- PJM sets the off-peak and on-peak regulation objectives.
- PJM is responsible for declaring and directing emergency actions.

<u>Major Differences for New York</u>:

- *New York meets its reserve and regulation requirements in both the DAM and HAM through a market-based scheduling process that co-optimizes energy and ancillary service bids.* ***[BP]***

<u>*Major Differences for New England*</u>:

NOTE: ISO New England has proposed to migrate to the PJM Platform. Accordingly, New England operational differences from PJM in the future would be limited throughout to differences necessary to accommodate: (1) the nature of New England resources (including renewable resources) and their ramping capability; (2) the location of New England on the grid; and (3) the contrast between the NPCC 30-minute reserve requirement and the MAAC 30-minute reserve objective.

Stakeholder-identified Sub-issues Pertaining to Control Area Operations

- See Appendix A-3.

Task Two: **Complete process of reviewing reliability rules, including local reliability rules and regulatory requirements, and determine regional requirements**

Complete: **Three months from Commission Order in this Proceeding**

- Address issues such as:
  - Degree of focus on localized system concerns
  - New York City reliability requirements
  - Process for development of RTO reliability requirements
  - Mechanisms for monitoring compliance with RTO reliability rules
  - Role of New York State Reliability Council
  - Standardization of reliability rules across the control areas
  - Relationship among NERC regions

Task Three: **Determine, as necessary, best practices (e.g., maintenance and transmission outage coordination)**

Complete: **Three months after Task Two**

- Address ISO-nominated best practices identified in this Business Plan in each of the following sub-areas:
  - Generation Scheduling
  - Transaction Scheduling
  - Generation Dispatch
  - Transmission Operations
  - Control Area Operations
- Address any other identified best practices in above sub-areas
- In determining best practices, address such issues:
  - Single or multiple set of operating standards across the control areas
  - Consistent operation of interties
  - Backup dispatch plans
  - Process for handling parallel flows
  - Handling of existing ISO to ISO agreements for particular facilities

- Dispatch signals to generators

Task Four: Develop operational requirements in conjunction with final market design

Complete: Three months after Task Three

- In developing operational requirements, address such issues as:
  - Unit commitment issues
  - Methodologies for communicating with generating and load resources
  - Treatment of intermittent resources
  - Handling of out-of-merit dispatch

Task Five: Complete operating manuals and procedures

Complete: Six months after Task Four[44]

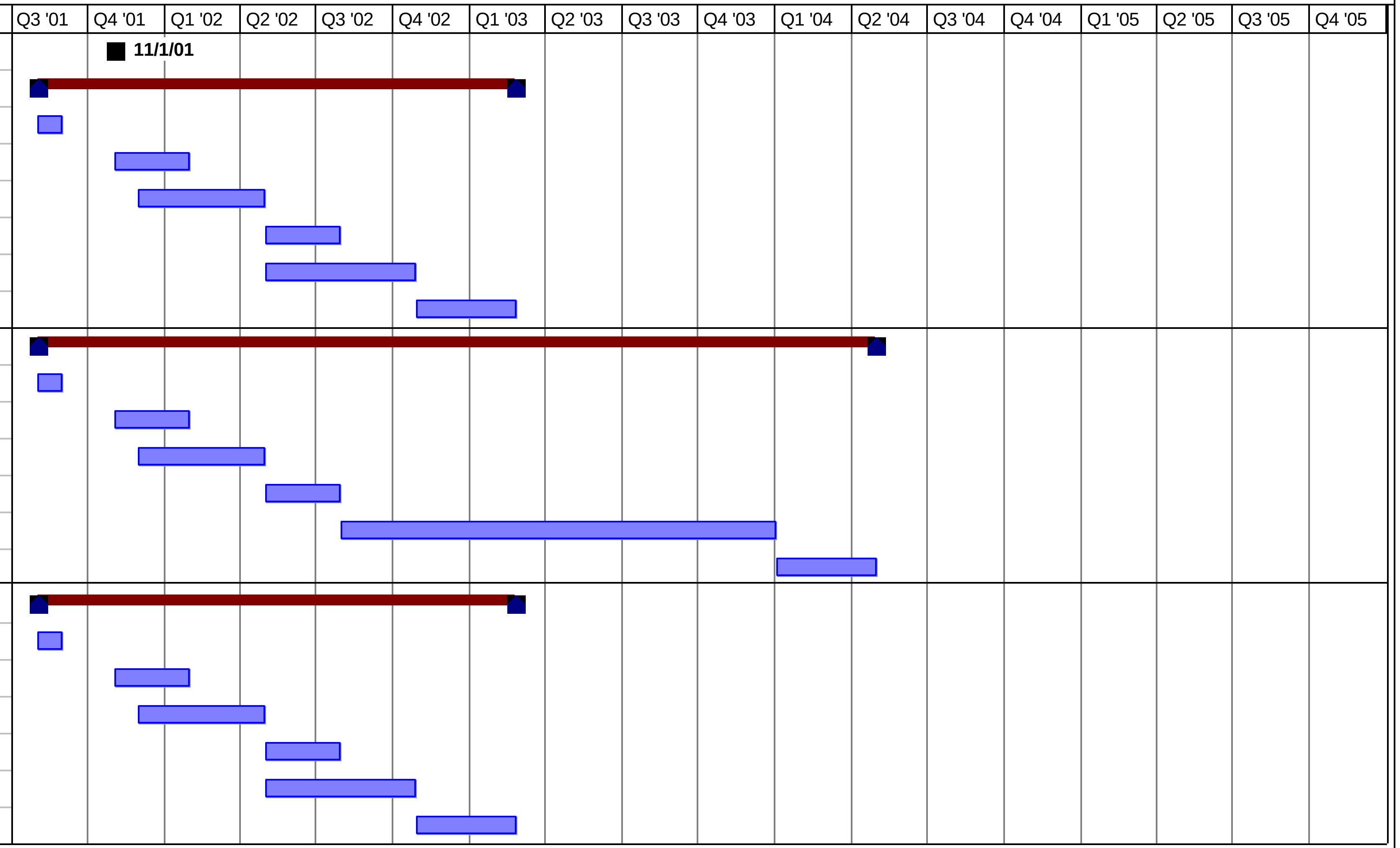
Task Six: Complete operations training including, as necessary, market trials

Complete: Four months after Task Five

[44] Market Design Option 2-M allows an additional 11 months for this task.

Northeast RTO Milestones for Operations

ID	Task Name
1	**Commission Issues Order on ALJ's Report**
2	**Operations (Option 1-M)**
3	Describe Platform and Differences
4	Complete Review of Reliability Rules
5	Determine, as required, Best Practices
6	Develop Operational Requirements
7	Complete Operating Manuals and Procedures
8	Complete Operations Training, and as necessary market trials
9	**Operations (Option 2-M)**
10	Describe Platform and Differences
11	Complete Review of Reliability Rules
12	Determine, as required, Best Practices
13	Develop Operational Requirements
14	Complete Operating Manuals and Procedures
15	Complete Operations Training, and as necessary market trials
16	**Operations (Option 3-M)**
17	Describe Platform and Differences
18	Complete Review of Reliability Rules
19	Determine, as required, Best Practices
20	Develop Operational Requirements
21	Complete Operating Manuals and Procedures
22	Complete Operations Training and, as Necessary, Market Trials



SECTION FIVE

RTO Technology Assessment

Task One: **Define parameters of technology assessment**

Complete: **Done**

- The business plan for transition to a Northeast RTO should include an assessment of the technologies to be employed. The technology assessment will address both IT infrastructure and applications. The following areas should be addressed:

    - Infrastructure

    - Integration architecture – Evaluate the ability to scale existing functions and add new capabilities needed to operate the northeast market.
    - Communications – Evaluate technologies for communications requirements for market systems and electric systems operations.
    - Failure recovery architecture – Evaluate redundancy requirements and operations within the RTO and at individual control centers, and consider disaster recovery.

    - Applications

    - Evaluate in the following areas the ability to scale existing functions and add new capabilities needed to operate the northeast market:

        - Security Constrained Unit Commitment (SCUC) system
        - Energy Management Systems
        - Billing and settlements systems
        - Market Information System

Stakeholder-identified Sub-issues Pertaining to Technology Assessment

- See Appendix A-4.

Task Two: **Develop primary alternative market models.[45]**

Complete: **NOTE: TASKS TWO THROUGH SEVEN SHOULD BE COMPLETED WITHIN SEVEN MONTHS OF THE COMMISSION ORDER IN THIS PROCEEDING**

[45] Base model requirements will include all existing operating requirements of the four control areas.

Task Three: Identify technology requirements

- Define scalability, performance, functional, and logistical requirements
- Consider technology requirements for best practice enhancements and “must-haves”

Task Four: Investigate infrastructure issues

- Integration Architecture—Evaluate the ability to scale existing functions and add new capabilities needed to operate the northeast market.
- Communications—Evaluate technologies for communications requirements for market systems and electric systems operations.
- Failure recovery architecture—Evaluate redundancy requirements and operations within the RTO and at individual control centers, and consider disaster recovery.
- Identify critical path software functions.

Task Five: Application adequacy assessment

- Security Constrained Unit Commitment (“SCUC”)
- Energy Management Systems
- Billing and Settlements Systems
- Market Information System

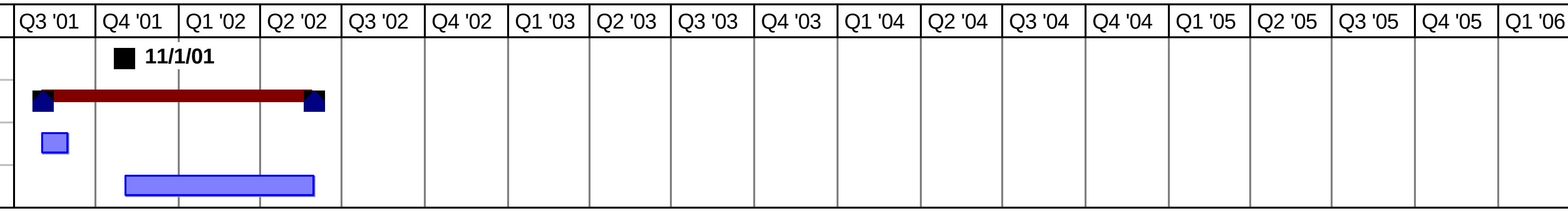
Task Six: Define implementation trade-offs

- Risk
- Cost
- Schedule
- Scope

Task Seven: Develop technology recommendation, including risk mitigation plan and trade-off assessment

Northeast RTO Milestones for Technology Assessment

ID	Task Name
1	**Commission Issues Order on ALJ's Report**
2	**Technology Assessment (All Options)**
3	Define Parameters
4	Technology Assessment



<u>SECTION SIX</u>

RTO Transmission Tariff

Task One: **Identify the Basic Elements of the PJM Platform on Transmission Tariff Design and the Differences from the Other ISOs in this Area, Including Their Nominated Best Practices**

Complete: **Done**

I. Transmission Tariff

PJM Platform

- One tariff for all transmission services and PJM administrative cost recovery.
- Transmission facilities included vary from zone to zone (generally 115 kv and above; but includes lower-voltage facilities in some zones).
- For transmission service for lower voltage facilities not included in PJM Tariff, rates are specified in service agreements administered under the PJM Tariff.

<u>Major Differences for New York</u>:

- *New York has both an OATT which defines the terms and conditions under which transmission customers receive transmission and ancillary services and a Services Tariff which covers the terms and conditions for the procurement of energy and ancillary services.*
- *There are differences in the treatment of several issues under these two tariffs (e.g. – liability provisions; balancing services).*
- *Most (but not all) Market Participants in New York are signatories to both Tariffs.*
- *In New York, there are specific transmission facilities which are under the operational control of the NYISO (as specified in Attachment A-1 of the NYISO/Transmission Owners Agreement); as well as facilities which require notification to the NYISO by the TO's (as specified in Attachment A-2 of the NYISO/TO Agreement).*
- *In New York, there are limited transmission facilities which are not covered under the NYISO's OATT (Alcoa).*

<u>Major Differences for New England</u>:

NOTE: For New England, the differences reflect a comparison of the PJM Tariff versus the current NEPOOL Tariff and ISO New England Tariff. The differences noted do not reflect revisions to these tariffs to reflect the proposed Standard Market Design. (In Section Six, brackets on New England items mean that the provision is included in the Commission-approved NEPOOL Transmission Tariff, but that it will not be implemented until congestion management in implemented in New England).

- *Transmission service in New England is provided under the NEPOOL Tariff and six local tariffs of the New England transmission owners. Some details of the congestion management system are contained in the Restated NEPOOL Agreement. In addition, ISO New England has a tariff for collection of its administrative costs, and a Capital Funding Tariff.*
- *The NEPOOL Tariff provides a regional arrangement which covers new uses (post March 1, 1997) of the NEPOOL Transmission System which is made up of the Pool Transmission Facilities ("PTF"). PTF are the transmission facilities owned by Participants rated 69 kV or above required to allow energy from significant power sources to move freely on the New England transmission network.*
- *Uses of transmission facilities that require the use of a single Participant Local Network continue to be provided in part under that Participant's filed tariff. Transmission-level resources are charged service under local tariffs when serving load outside the local utility's service territory.*
- *Rates for certain tie facilities operated by ISO New England (e.g., Hydro Quebec Phase I/II), are not collected under the NEPOOL Tariff but under separate tariffs of the tie owners. Scheduling practices differ for these facilities, compared with tie facilities that are Pool Transmission Facilities.*
- *Regional and local tariffs apply to resource interconnection.*

Stakeholder-identified Sub-issues Pertaining to Transmission Tariff

- See Appendix A-5

II. Network Transmission Service

PJM Platform

- As a result of the PJM market design, load generally utilizes network transmission service.
- Network load is defined as load plus losses.
- Designated network resources are same as resources used to meet capacity requirements.
- Network service customers annually can request FTRs from network resources to load; FTR analysis is a simultaneous feasibility analysis for all requests (pro rata reductions if all FTRs cannot be accommodated). Changes to network service FTRs can be requested daily.
- Network load has no requirement to provide balanced schedule; all imbalances are handled in the spot market at the clearing price (with no penalties or bandwidth).
- Designated resources for network load can be external if firm ATC into PJM is available.
- Non-designated resources can be imported using secondary network service, up to the customer's load.
- Service using designated and non-designated resources is requested through OASIS.

<u>Major Differences for New York</u>:

- *As a result of the NYISO market design, load generally uses point-to-point transmission service; therefore, network import procedures have not been necessary.*
- *New York has no TCC allocations based on network load or generation. With the exception of certain grandfathered agreements, all TCC's, including those for native load, are obtained through periodic auctions.*
- *In New York, TCC's are awarded for transmission expansion.*
- *In New York, loads which are signatories to the NYISO Services Tariff are balanced at the real-time market LBMP; loads which are signatories to only the NYISO OATT are subject to both bandwidth and penalty requirements.*

<u>Major Differences for New England</u>:

- *In New England, network loads do not designate network resources for the purposes of transmission service. The distinction between firm and non-firm (or secondary) network service that is made in PJM is not made in New England.*
- *[FTRs are not assigned to network load. Network service customers can procure FTRs bilaterally or through periodic FTR auctions conducted by the ISO.]*
- *[Auction Revenue Rights ("ARRs") are allocated to Congestion Paying Entities, Transmission Customers, NEMA LSEs and generators funding Generator Interconnection Related Upgrades (including any of the foregoing that are parties to Excepted Transactions that are included in the list of transactions in Attachments G and G-2 of the NEPOOL Tariff) using a four-stage process. The process determines a set of ARRs that is simultaneously feasible. ARRs are rights to receive FTR Auction Revenues from the sale of FTRs other than FTRs sold by FTR Holders.]*
- *[An entity who pays for new transmission upgrades which increase transfer capability on the NEPOOL Transmission System, making it possible for ISO NE to award additional FTRs in the FTR Auction, will be awarded ARRs. The amount of ARRs awarded to such an entity will be consistent with the FTRs that were made possible by the transmission upgrade. The award will be in direct proportion to the percentage of the costs of the upgrade paid by such entity, and will continue for so long as the entity supports the costs of the upgrade.]*
- *[To the extent that transmission upgrades resulting in new transfer capability are paid for through the Pool RNS Rate, any ARRs associated with the sale of FTRs made possible by such upgrades will be allocated to Transmission Customers and Congestion Paying Entities on a Monthly Peak Load basis.]*
- *The NEPOOL Tariff allows import transactions in conjunction with Regional Network Service where no OASIS reservations are required. **[BP]***

Stakeholder-identified Sub-issues Pertaining to Network Transmission Service

- See Appendix A-5

III. Firm Point-to-Point Transmission Service

PJM Platform

- The PJM Tariff offers pro-forma firm point-to-point transmission service within, into, out of, and through the service area.
- Length of service is from one day to multi-year; requests may be made at any time for service of one year or more, starting 18 months in advance for monthly service, starting 2 weeks in advance for weekly service, and starting 3 days in advance for daily service.
- Available Transmission Capacity (ATC) values are posted on a FERC compliant OASIS system on a path-specific basis for all paths; firm service requests are granted and approved based on the physical capabilities of the transmission system.
- Firm transmission customers may request FTRs to hedge against congestion; FTR requests are analyzed for simultaneous feasibility separately from the physical request.
- Firm ATC calculation method is posted on the OASIS.
- FTRs are tradeable.

Major Differences for New York:

- *In New York, long-term firm transmission service is provided through grandfathered transmission rights based on pre-existing contracts.*
- *In New York, the financial equivalent of long-term transmission service is provided through long-term TCC's procured at auction.*
- *All other transmission service is scheduled on a day-ahead or hour ahead basis integrated with the submission of bids or schedules in the day-ahead or real-time market.*
- *[While no other long term firm transmission service is currently available on interconnections, New York will implement the prescheduling of long-term energy and transmission service (of at least 18 months) early in 2002.]*
- *In New York all TCC's are procured through periodic TCC auctions conducted by the NYISO (except for grandfathered contracts and expansion based TCC's). There are no other allocation mechanisms.*
- *In New York, TTC and ATC is posted on an interface-specific basis for inbound transactions; TRM is not posted.*
- *In New York, all TCC's are fully funded.*

Major Differences for New England:

- *The NEPOOL Tariff offers pro-forma firm point-to-point transmission service within, out of, and through the service area: Internal Point-to-Point Service and Through or Out Service.*
- *The NEPOOL Tariff allows import transactions in conjunction with Regional Network Service where no OASIS reservations are required.*
- *[FTRs are not assigned to firm point-to-point transmission customers. Such customers can procure FTRs bilaterally or through periodic FTR auctions conducted by the ISO.]*

- *Requests for firm point-to-point transmission service may be made at any time for service of one year or more, starting 6 calendar months in advance for monthly service, 3 calendar weeks in advance for weekly service, and 6 calendar days in advance for daily service.*
- *[NEPOOL has approved a pilot that would provide incentive payments to transmission providers for innovative transmission maintenance that reduces congestion.]* ***[BP]***

Stakeholder-identified Sub-issues Pertaining to Firm Point-to-Point Transmission Service

- See Appendix A-5

IV. Non-Firm Point-to-Point Transmission Service

PJM Platform

- The PJM Tariff offers pro-forma non-firm point-to-point service.
- Length of service is from one hour to one month.
- ATC values are posted on a FERC compliant OASIS system; non-firm service requests are granted and approved based on the physical capabilities of the transmission system.
- Non-firm transmission service customers may elect to pay re-dispatch costs (“buy through” congestion) in lieu of being curtailed. Non-firm customers may specify “up to” congestion costs in the Day Ahead Market and may curtail transactions with 20 minutes’ notice in the real time market to avoid congestion charges.
- Third parties that would be subject to NERC transmission loading relief (invoked by PJM) similarly can avoid curtailment by electing to pay re-dispatch costs (“TLR buy-through”).
- The non-firm transmission reservation process does not provide FTRs (if desired, non-firm customers may obtain FTRs bilaterally or in monthly auctions).

Major Differences for New York:

- *In New York, non-firm transmission service is always available in the day-ahead and real-time markets whenever there is no congestion.*
- *Non-firm transmission service is curtailed when congestion is present.*
- *New York rarely has the need to invoke TLRs since it continually redispatches its system to support all scheduled transactions and unscheduled loop flows.* ***[BP]***
- *In New York, TCC’s are available to all Market Participants via periodic auctions.*
- *In New York, the ability to “buy through” congestion up to a certain amount only applies to wheel through transactions.*

Major Differences for New England:

- *The NEPOOL Tariff offers pro-forma non-firm point-to-point transmission service within, out of, and through the service area: Internal Point-to-Point Service and Through or Out Service.*

- *The NEPOOL Tariff allows import transactions in conjunction with Regional Network Service where no OASIS reservations are required.*
- *New England has not invoked TLRs, due to its location on the grid.*

Stakeholder-identified Sub-issues Pertaining to Non-Firm Point-to-Point Transmission Service

- See Appendix A-5

V. Transmission for Retail Access

PJM Platform

- Load-serving entities purchase network service for retail access load, pursuant to a standard form umbrella service agreement. Transmission customers are state-certified load aggregators and must become PJM members.
- Incumbent utilities and alternative suppliers take retail-access transmission service under the same terms and conditions.
- Transmission customers arrange for Electric Distribution Companies ("EDCs") serving their load to report their retail customers' peak load levels to PJM.
- Transmission customers designate network resources and schedule directly with PJM their energy requirements against their hourly loads, as reported by the EDC.
- Retail-access customers resolve their energy imbalances by buying from, or selling to, the energy market at LMP.
- Transmission customers who have source-specific ICAP generation may request assignment of FTRs, including changes as necessary to reflect their changes in load from time to time.
- PJM transmission and capacity obligations are posted prospectively and not subsequently adjusted.
- PJM accommodates scheduling to the tenth of a megawatt.
- PJM can terminate service immediately to retail-access transmission customers that are in default if the retail customer is switched by operation of state law to a new supplier.
- Load shedding for retail-access customers is on an EDC-by-EDC basis.
- Prospective retail-access transmission customers applying for service need not provide information regarding long-term load and resource forecasting; such information is provided by the EDCs.
- Minimum term of service for retail-access network transmission is one day.
- Because their loads may change frequently, retail-access transmission customers designate network load via PJM's electronic information system, rather than in the service agreement.
- Monthly demand charge is calculated as the sum of daily demand charges, to account for changes in loads.
- PJM has a tightly integrated set of systems with EDCs to accommodate state-authorized retail access, including scheduling, settlement, billing, and reconciliation.

<u>*Major Differences for New York*</u>***:***

- *For retail access, Eligible Customer defined as any retail customer taking unbundled transmission service. Transmission Customers under the NYISO*

OATT can include Energy Service Companies, aggregators, utilities, or dirct customers.

- *Customers must schedule in whole megawatt increments.*
- *Eligible Customer must be taking service under a NYS PSC-approved (or LIPA approved) retail access program.*
- *Eligible Customers must become a Transmission Customer under the NYISO OATT unless they select a Load-serving Entity (“LSE”) to procure transmission service on their behalf.*
- *New York has specific tariff provisions regarding scheduling over LIPA’s transmission facilities and treatment of LIPA’s retail access programs which protect tax-exempt financing of LIPA’s facilities.*
- *In New York, there is a retail transmission service charge (“TSC”) under the New York OATT, among other charges, which are applicable to transmission owners’ retail access programs.*
- *Eligible Customers responsible for paying retail TSC to TO, among other charges, per Part IV of the NYISO OATT and the TO’s retail access tariff. Retail customers are billed the retail TSC even when service is provided through an LSE.*
- *LSEs (including Eligible Customers serving as their own LSE) are responsible for paying all NYISO charges, including, without limitation, energy (day-ahead and real-time), ancillary services, NTAC and the TUC.*
- *LSEs (including Eligible Customers serving as their own LSE) are responsible for scheduling Transmission Service, providing forecasts to Eligible Customers.*
- *LSEs must satisfy NYISO requirements, including whole MW transactions.*
- *LSEs participating in TO retail access must sign service agreement as Transmission Customer and agent for retail access customers.*
- *Rates, collection and billing procedures for retail access Transmission Service provided pursuant to part IV of the NYISO OATT and generally through TO’s retail access tariff.*
- *TO can unilaterally modify its retail access tariff subject to regulatory filing.*
- *TO can make a §205 filing to unilaterally modify its retail transmission rates, charges, terms, and conditions.*
- *NYISO settlement procedures coordinate with TO retail access tariffs.*
- *NYISO implements any tariff changes to handle modifications to retail transmission charges.*
- *NYISO provides retail access services to Eligible Customers taking Unbundled Transmission Service.*
- *Eligible Customer or LSE/aggregator (>1mw) must provide bids or bilateral schedules directly to the NYISO.*
- *NYISO bills on an energy basis LSE (or Eligible Customer serving as their own LSE) based on their actual load (as provided by the transmission owner in accordance with its retail access tariff.*
- *TO’s read Eligible Customers’ meters after the fact.*
- *NYISO reconciles LSE/Eligible Customer load values based on a scheduled true-up process to account for better data that is received after the billing month.*
- *In New York, there is no assignment of TCCs associated with retail access programs.*

Major Differences for New England:

- *Retail access is accommodated in a variety of ways under the local network service tariffs of the transmission owners.*
- *Five of the six New England states currently permit retail wheeling.*
- *Distribution service and service across non-PTF are available under separate tariffs of the individual Transmission Owners.*
- *Service across PTF is available to retail customers directly under the NEPOOL Tariff if permitted by applicable state regulations, or indirectly through the distribution utility purchasing service on behalf of its wires customer.*
- *Scheduling is on a whole-megawatt basis.*

Stakeholder-identified Sub-issues Pertaining to Transmission For Retail Access

- See Appendix A-5

VI. Tariff Rates

PJM Platform

- Transmission owners set their revenue requirements under the Federal Power Act (subject to FERC acceptance) on a stated-rate, zonal basis; network rate design is based on the same design used for annual allocations of FTRs (1 CP), while point-to-point rate design is 12 CP.
- Network service pays "license plate" rate of the transmission zone of the load; network service demand charges are based on the customer's coincident zonal peak load in its transmission zone.
- "Through" and "out" firm point-to-point transmission services pay a weighted average border rate for the megawatts reserved.
- Firm point-to-point service into the control area pays the zonal rate of the sink of the service for the megawatts reserved.
- Non-firm transmission rates are the same as firm, but are discounted (currently to the higher of congestion costs or $0.67/MWh).
- Congestion (redispatch) charges for all transmission services equal the difference in locational marginal prices (LMPs) between the sources and sinks.
- Sales into the spot market are assumed to use secondary network service of the load and therefore need not incur any further transmission charge.
- Network transmission revenues are distributed to the transmission owners in the zone; firm point-to-point revenues distributed to transmission owners on a pro rata revenue requirements share basis; non-firm revenues distributed pro rata to all firm transmission customers (network and point-to-point).
- PJM collects its costs through formula rates set forth in Schedule 9 of the PJM Tariff, which enable PJM to collect all accrued costs monthly from transmission and other PJM customers on an unbundled basis.
- Transmission owner local control center costs are collected from zonal load under a separate schedule of the PJM Tariff.
- For the expansion of the PJM Tariff to the PJM West region, the Commission has approved the concept of Allegheny's entitlement to recover lost revenues, associated with its joining PJM, through transitional surcharges.

- PJM must complete an evaluation of the design of its license plate rates and file its recommendations on any changes that should be instituted by January 1, 2003. In PJM West, the Commission approved the use of a license-plate rate design through December 31, 2004.
- Non-jurisdictional entities' revenue requirements may be collected through the zonal rates.

<u>*Major Differences for New York*</u>:

- *In New York, Transmission Owners' Section 205 rights are applicable to both their transmission revenue recovery as well as retail access programs.*
- *In New York, the NYISO Board has the right to make an independent section 205 filing in "exigent circumstances." Such filings, unless approved by FERC under section 206, will sunset in 120 days absent concurrence of the Management Committee.* ***[Possibly impacted by FERC's July 12, 2001 RTO Order]***
- *In New York the billing units for the wholesale Transmission Service Charge (TSC) are based on the annual energy requirements of each Transmission District and are paid on each Mwh withdrawn from the NY transmission grid.*
- *In New York, the TSC is paid by wholesale customers with any exceptions enumerated in Attachment K of the NYISO OATT.*
- *In New York, through and export transactions pay a weighted average border rate based on actual energy deliveries.*
- *In New York, the TSC is a formula rate that is updated monthly. Adjustments are applied to account for revenues from grandfathered wheeling contracts, revenue from TCC auctions, congestion revenues and wheel through and export transactions.*
- *In New York, the TOs directly bill wholesale customers for the TSC.*
- *In New York, the Transmission Usage Charge (TUC) includes the cost of congestion and marginal losses from the point of receipt to the point of delivery.*
- *In New York, the NYPA Transmission Adjustment Charge (NTAC) is applied to all loads in the NYCA and through and out wheels.*
- *In New York, there is a separate wholesale TSC for certain NYPA customers.*
- *The NYISO tariff recognizes the non-jurisdictional status of LIPA by providing that revenue requirements for LIPA are solely subject to review under applicable State laws.*
- *The NYISO collects its costs through a formula rate collected through the NYISO OATT on a bundled basis (through Rate Schedule #1), with the exception of the recovery of start-up costs, which are allocated between the OATT and Services Tariffs.*
- *The Schedule 1 costs are paid by all NYCA loads, wheeled through and export transactions on the basis of energy use.*
- *The TO's control center costs are recovered through the individual TSC's which are allocated by Transmission District.*

<u>*Major Differences for New England*</u>:

- *Tariff rates in New England are the product of a FERC approved multilateral, multi-year settlement.*

- *Transmission Providers collect their revenue requirements through a combination of revenues received under a formula rate in the NEPOOL tariff and under their individual local tariffs. Changes to the NEPOOL Tariff are subject to NEPOOL governance, with express rights for Transmission Owners to change their revenue requirements (subject to FERC acceptance) and there is an unresolved issue of the Transmission Owners' rights to make changes to the NEPOOL Tariff.*
- *Under the tariff settlement transitional mechanisms for NEPOOL, the PTF rate (RNS) is designed to move all charges for service over PTF to a uniform region-wide rate by October 2009, with charges under local tariffs ultimately covering service only on non-PTF facilities. As a result, currently, network service effectively pays the "license plate" like rate of the transmission zone of the load through a combination of the charges for service under the local tariff and NEPOOL (RNS) tariff during the transitional period.*
- *Through or Out Service customers pay the Pool PTF rate; Through or Out service charges are based on customer's reserved capacity. The firm and non-firm Pool PTF rate is the same, except for daily firm service which is one-fifth of the weekly rate (provided that the rate for 5 to 7 consecutive days may not exceed the per week rate) and daily non-firm service which is one-seventh the weekly rate.*
- *The allocation of Through or Out Service charges to the appropriate Transmission Owners is based on flow distribution factors between the transaction's Point of Receipt and Point of Delivery. However, from March 1, 1997 through March 1, 2003, if the Through or Out transaction's Point of Receipt is a Local Network adjacent to the Point of Delivery, then the Transmission Owner of such Local Network receives 100% of the revenue from such transaction.*
- *[Congestion (redispatch) charges for all Non-Participant transmission customers equals the difference in LMPs between the sources and sinks.]*
- *Currently, congestion is socialized, and paid based on customers' Network Load and/or Reserved Capacity.*
- *[For external energy transactions associated with non-firm point-to-point service whose congestion costs exceed its transmission charges, the transmission charges are not rebated to the transmission customer.]*
- *ISO New England collects its costs through stated rates in its own tariff. Rate design is somewhat formulaic and the product of a settlement. Other costs for scheduling and dispatch that are incurred by transmission owners are recovered pursuant to a formula rate in Schedule 1 of the NEPOOL Tariff which allocates all such costs in accordance with Network Load and Reserved Capacity.*
- *Discounting is permitted, but does not occur at present under the NEPOOL Tariff. Some Transmission Owners grant discounts under their local tariffs.*
- *Non-jurisdictional entities' transmission-related revenue requirements are collected through the NEPOOL Tariff rates.*
- *The costs of transmission expansions not related to generation interconnections are rolled into the regional transmission rates.*
- *ISO-NE does not have 205 rights concerning the NEPOOL tariff.*

Stakeholder-identified Sub-issues Pertaining to Tariff Rates

- See Appendix A-5

VII. Reactive Supply and Voltage Control from Generation Sources Service

PJM Platform

- Each generation owner receives a monthly credit for providing this service based on $1/12^{th}$ of its annual reactive revenue requirement.
- The transmission customer's charge is based on its monthly zone and non-zone transmission use. The sum of all transmission customers' monthly charges equals $1/12^{th}$ of the total annual revenue requirements that are credited to generation owners.
- Generators are paid lost opportunity costs for operating off-cost to provide VARs when requested by PJM.

Major Differences for New York:

- *In New York, reactive services are procured by the NYISO under a cost-based rate.*
- *In New York, reactive service costs are paid by load based on energy use.*
- *In New York, generators are paid based on demonstrated VAR capability with penalties for non-performance.*

Major Differences for New England:

- *Under the NEPOOL Tariff, compensation to generators in providing this service is based on four components: Capacity Cost (CC), Lost Opportunity Cost (LOC), Cost of Energy Consumed (SCL) and Cost of Energy Produced (PC).* ***[BP]***
- *The charges for this service recover both fixed costs (CC) and variable costs determined on an hourly basis (LOC, SCL and PC).*
- *Network customers are charged based on Network Load for the hour. Point-to-Point customers are charged based on Reserved Capacity for the hour.*

Stakeholder-identified Sub-issues Pertaining to Reactive Supply and Voltage Control from Generation Sources Service

- See Appendix A-5

VIII. Energy Imbalance Service

PJM Platform

- PJM uses the real-time energy market to resolve imbalances.

Major Differences for New York:

- *In New York, loads which are signatories to the NYISO Services Tariff are balanced at the real-time LBMP.*
- *In New York, loads which are signatories to only the NYISO OATT are subject to both bandwidth and penalty requirements.*

Stakeholder-identified Sub-issues Pertaining to Energy Imbalance Service

- See Appendix A-5

IX. Black Start Service

PJM Platform

- There is no separate and defined compensation to generators for Black Start services.

  <u>*Major Differences for New York*</u>*:*

  - *In New York, there is a cost-based black-start service related to restoration needs of the bulk transmission system. The cost for such service is allocated to all load on a statewide basis based on energy use.*
  - *In New York, there is also a provision for cost-based local black-start service. The cost of such service is allocated to loads on a Transmission District basis.*

  <u>*Major Differences for New England*</u>:

  - *Under the NEPOOL Tariff, each designated "Black Start Generator" is paid its own fixed monthly revenue requirement. A new generator that is designated as a "Black Start Generator" that does not have sufficient historical data to determine its annual revenue requirement is paid the average black start payment.* ***[BP]***
  - *Network customers and Internal Point-to-Point customers are charged for their pro-rata share of this service based on their monthly Network Load and maximum Reserved Capacity (including unauthorized use), respectively. Through or Out customers are not charged for this service.*

Stakeholder-identified Sub-issues Pertaining to Black Start Service

- See Appendix A-5

X. Losses

PJM Platform:

- PJM allows External Transactions greater than 199 MW to have either in-kind or financial losses applied. Losses are settled as metered demand at the marginal price.
- PJM calculates losses on an average, fixed-fee basis. (2.5% or 3%).

  <u>*Major Differences for New York*</u>*:*

  - *In New York, marginal losses are calculated from the point-of-receipt to the point-of-delivery for all transactions and are included in the TUC.* ***[BP]***
  - *In New York, all transactions may self-supply losses by scheduling injections in excess of withdrawals.*

  <u>*Major Differences for New England*</u>:

- *[In New England, the cost of PTF losses will be recovered solely through the Marginal Loss component (i.e., financial) of the LMP.]*
- *There are different loss recovery mechanisms under each of the local tariffs.*

Stakeholder-identified Sub-issues Pertaining to Losses

- See Appendix A-5

XI. Excepted Transactions

- All three ISOs have grandfathering provisions that will need to be reconciled.

Stakeholder-identified Sub-issues Pertaining to Excepted Transactions

- See Appendix A-5

Task Two: Resolution of fundamental issues of RTO market design (starting point)[46]

Complete: Per Task Two in Market Design

Task Three: Reach agreement on defining the elements of a starting-point framework for RTO Transmission Tariff and other issues

Complete: Two months after Task Two

- Terms and Conditions should be based on FERC Pro Forma model, as modified by PJM, NYISO and NEPOOL Tariffs

Task Four: Address issues and identify best practices as necessary to finalize RTO Tariff and documents containing resolution of related issues

Complete: Four months after Task Three[47]

- Identify and agree on best practices to enhance PJM platform in the following areas:
  - Tariff Design
  - Network Transmission Service
  - Firm Point-to-Point Transmission Service

[46] Resolution of tariff issues not dependent on market design can commence earlier.

[47] Option 2-M allows an additional three months to complete this task.

- Non-Firm Point-to-Point Transmission Service
- Transmission for Retail Access
- Tariff Rates
- Reactive Supply and Voltage Control from Generation Sources Service
- Energy Imbalance Service
- Black Start Service
- Losses

- Resolve related issues, including:
  - Non-Rate Terms and Conditions
  - Scope of Facilities Subject to RTO Tariff
  - Accommodation of Merchant Transmission Projects
  - Service Availability and Use
  - Scope of Service Offered
  - Necessary Contracts
  - Maintenance Scheduling and Planning

Task Five: **File necessary market-related transmission provisions**

Complete: **Per Task Five in Market Design**

- Draft market-related transmission provisions and other necessary documentation
- Stakeholder review of draft provisions and other operative documents, and revise as appropriate in response to stakeholder review (iterative process)
- File with FERC

Task Six: **Evaluate rate issues**

Complete: **Four months after Task Four**

- Rate issues include:
  - Recovery mechanisms for transmission revenue requirements
  - Develop rate designs as necessary
  - Lost revenue transition mechanisms as the result of the integration of the ISOs
  - Accommodation of existing (grandfathered) contracts, settlements and other arrangements

Task Seven: **Develop potential incentive rate concepts and mechanisms**

Complete: **In parallel timeframe with Task Six**

- Development of potential incentive rate concepts and mechanisms should address such issues as:
  - The types of entities that can qualify for incentive rates

- Revenue neutrality of incentive rates
- Determining the baseline performance which must be exceeded in order to receive agreed incentive
- Incentive rates for the RTO itself
- Incentive rate mechanisms for generation and demand-side solutions to congestion
- Use of incentive rates in the contexts of transmission expansion, upgrades, maintenance

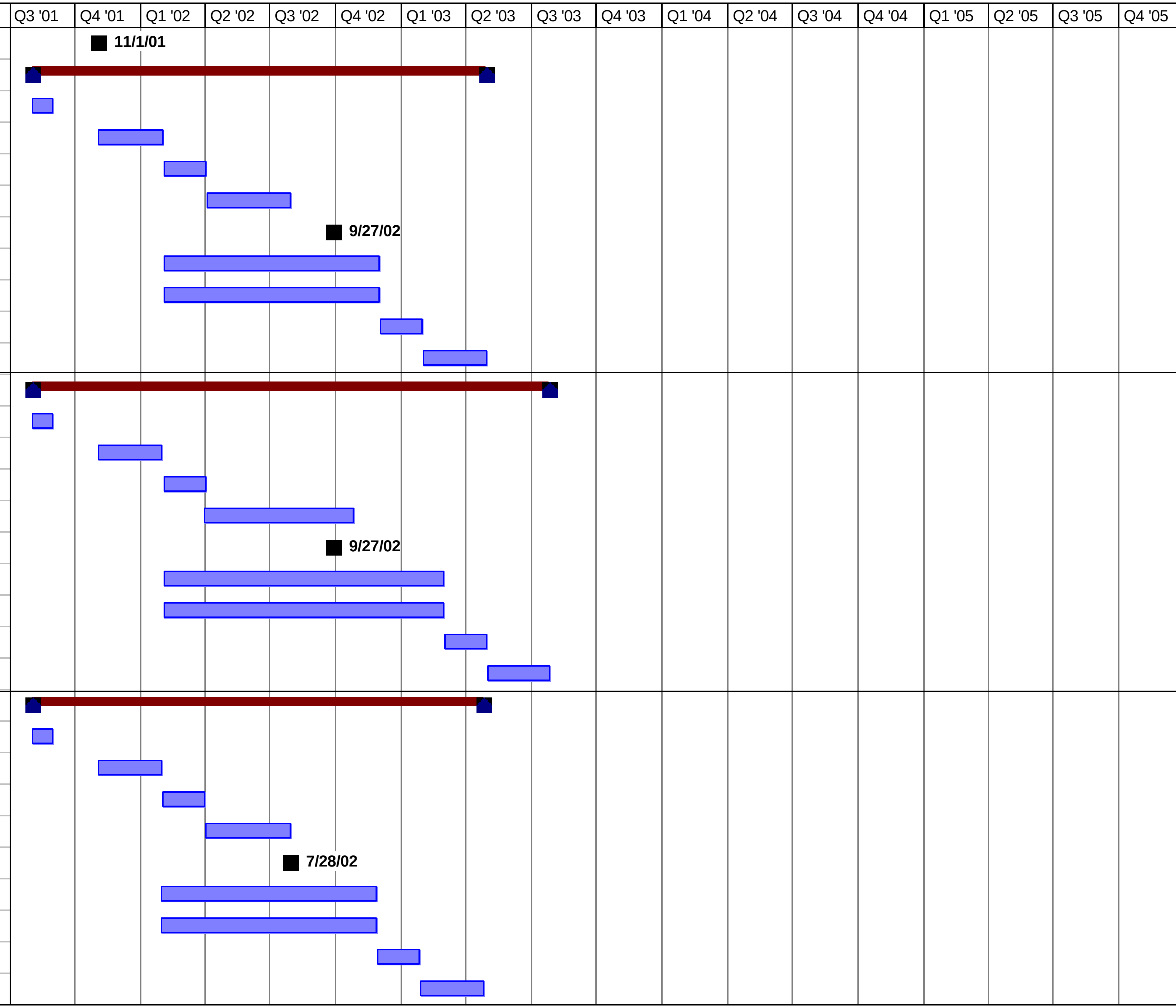
Task Eight: Finalize tariff and other documentation and file with FERC

Complete: Two months after Task Seven

- Draft tariff and other necessary documentation
- Stakeholder review of draft tariff sheets and other operative documents, and revise as appropriate in response to stakeholder review (iterative process)
- File with FERC

Northeast RTO Milestones for Transmission Tariff

ID	Task Name
1	**Commission Issues Order on ALJ's Report**
2	**Transmission Tariff (Option 1-M)**
3	Describe Platform and Differences
4	Resolution of Fundamental Issues of Market Design
5	Agreement on defining elements of starting-point framework
6	Address issues, identify best practices to finalize Tariff
7	File Market-Related tariff provisions
8	Evaluate Rate Issues
9	Develop Potential Incentive Rate Concepts
10	Finalize Tariff and other Documentation and File with FERC
11	FERC Approval
12	**Transmission Tariff (Option 2-M)**
13	Describe Platform and Differences
14	Resolution of Fundamental Issues of Market Design
15	Agreement on defining elements of starting-point framework
16	Address issues, identify best practices to finalize Tariff
17	File Market-Related Tariff Provisions
18	Evaluate Rate Issues
19	Develop Potential Incentive Rate Concepts
20	Finalize Tariff and other Documentation and File with FERC
21	FERC Approval
22	**Transmission Tariff (Option 3-M)**
23	Describe Platform and Differences
24	Resolution of Fundamental Issues of Market Design
25	Agreement on defining elements of starting-point framework
26	Address issues, identify best practices to finalize Tariff
27	File Market-Related tariff provisions
28	Evaluate Rate Issues
29	Develop Potential Incentive Rate Concepts
30	Finalize Tariff and other Documentation and File with FERC
31	FERC Approval



SECTION SEVEN

RTO Regional Planning (including Transmission Planning, Generation Interconnections, and Cost Allocation/Property Rights)

Task One: **Identify the Basic Elements of the PJM Platform on Regional Planning and the Differences from the Other ISOs in this Area, Including Their Nominated Best Practices**

Complete: **Done**

I. Transmission Planning Process

A. Transmission Planning

PJM Platform

- The RTO is responsible for planning and directing transmission expansions, additions, and upgrades.
- The RTO has the ultimate responsibility for developing plans and conducting the studies that are required to develop the plan.
- The RTO Board approves the final transmission expansion plan.
- The RTO, through an open stakeholder process featuring a transmission expansion advisory committee, receives input from all interested parties regarding the proper scope, assumptions, and procedures for expansion studies.
- The stakeholder process includes coordination with state regulatory and environmental bodies.
- Transmission studies are conducted either solely by the RTO or with the assistance of the transmission owners acting under the direction of the RTO.
- Transmission owners and other market participants supply needed data and supporting analyses, under the direction of the RTO.

Major Differences for New York:

- *NYISO RTO proposal provides for a transmission planning committee that is not advisory-only.* ***[possibly impacted by FERC's 7/12/01 RTO order]***
- *NYISO RTO proposal provides that the NYISO Board has authority to either approve the transmission planning committee's plan or return it to the committee for more work.* ***[possibly impacted by FERC's 7/12/01 RTO order]***
- *NYISO RTO proposal provides for protection of cost recovery for transmission owners.* ***[possibly impacted by FERC's 7/12/01 RTO order]***

Major Differences for New England:

- *ISO-NE has a cycle for planning, which is an ongoing process over a three-year period (updated at least annually), which differs from PJM's cycles.* ***[BP]***
- *ISO-NE explicitly considers market participants' demand-side and generation-side alternatives and merchant transmission projects.* ***[BP]***

- *Under the proposed New England RTO planning process, Independent Transmission Companies (ITCs) would participate in the planning process.*

B. Transmission Owner Responsibilities

PJM Platform

- The transmission owners are obligated to construct the facilities identified by the plan approved by the Board. To date, the PJM Board has only required reliability-based expansions. [The Commission has ordered that the RTO must also consider economic expansions that support competition.]
- Merchant transmission may also be accommodated.
- The plan should accommodate the ability of third parties to build and own transmission facilities identified in the plan.

Major Differences for New York:

- *NYISO provides incremental property rights (TCCs) for merchant transmission* ***[BP]***
- *NYISO RTO proposal provides that NYISO may only direct construction for reliability-based expansions* ***[possibly impacted by FERC's 7/12/01 RTO order]***
- *NYISO RTO proposal provides that transmission owners will build subject to assurance of cost recovery, siting, local permits, etc., or order by state PSC.* ***[possibly impacted by FERC's 7/12/01 RTO order]***

Major Differences for New England:

- *ISO-NE explicitly addresses merchant transmission.* ***[BP]***
- *ISO-NE has an RFP process regarding transmission construction.*

C. Stakeholder Involvement

PJM Platform

- The RTO, in conjunction with the stakeholders, recommends a plan to the RTO Board.
- Stakeholders may present alternatives to the plan.
- ADR is available following plan approval by the Board.

Major Differences for New England:

- *Under the ISO-NE planning process, there is a public meeting with a subcommittee of the Board before the Board adopts a plan.* ***[BP]***
- *ISO-NE does not have an ADR process for disputes following plan approval.* ***[BP]***

D. Major Plan Considerations

PJM Platform

- maintaining reliability, and
- accommodating all transmission service requests; and
- the Commission has ordered consideration of economic expansions to support competition.

E. Stakeholder-identified Sub-issues Pertaining to Transmission Planning

- See Appendix A-6.

II. Generation Interconnection Process

PJM Platform

- The RTO Tariff includes a standardized generation interconnection process. Currently, PJM enters into study agreements and interconnection service agreements with generators, and the transmission owners enter into interconnection agreements and construction agreements with the generators.
- The RTO will develop appropriate mechanisms for contracting with generators and the transmission owners to cover these matters.
- Transmission facilities required to accommodate the interconnection of generation resources are included in the RTO transmission plan approved by the Board.
- Generation projects are queued for evaluation on a first come, first served basis, with defined milestone requirements for a project developer to maintain its queue position.
- Generation projects are evaluated on the basis of non-firm, energy-only sales, or on the basis of the right to sell firm capacity, at the election of the generator.
- There is an expedited process for generators smaller than 10 megawatts.
- The RTO has responsibility for all studies required to accommodate generation interconnections.
- Transmission studies are conducted either solely by the RTO or with the assistance of the transmission owners acting under the direction of the RTO.
- Transmission owners and other market participants supply needed data and supporting analyses, under the direction of the RTO.
- [The Commission has ordered that the interconnection process must be under the decisional control of the RTO and the RTO must be responsible for all aspects of the interconnection process.]
- [The Commission has ordered that customers should deal with and sign interconnection and study agreements with the RTO.]
- There are three stages to the interconnection process, Feasibility, System Impact, and Facilities Design and Construction.
- ADR is available for disputes regarding the interconnection process.

<u>*Major Differences for New York:*</u>

- *NYISO does not have a "deliverability" concept.* ***[BP]***
- *NYISO interconnection procedures only apply above a certain project-size threshold.*

- *NYISO has a two-stage interconnection process: System Impact and Facilities Studies.*

<u>*Major Differences for New England:*</u>

- *ISO-NE does not have a "deliverability" concept, which may affect cost allocations, and conducts studies based on a "Minimum Interconnection Standard."*
- *ISO-NE has a "construction sequencing" process, which affects allocation of costs.* ***[BP]***
- *ISO-NE has an expedited "subordinated 18.4" process if the generator agrees to "at-risk" interconnection.* ***[BP]***
- *No provision for an expedited interconnection process exists in ISO-NE.*
- *ISO-NE has a two-stage interconnection process: System Impact and Facilities Studies.*
- *[Hybrid RTO proposal assigned responsibility to ITC (or other responsible entity)]* ***[possibly impacted by FERC's 7/12/01 RTO order]***

Stakeholder-identified Sub-issues Pertaining to Generation Interconnection

- See Appendix A-6

III. Cost Allocation and Property Rights

PJM Platform

- Except as stated below, the cost of transmission upgrades determined through the planning process are allocated either by unanimous agreement among the transmission owners and other entities that have indicated a willingness to bear some or all of the cost responsibility, or by a specific default allocation mechanism (specified in Section 6 of the PJM Operating Agreement) among the transmission owners based on location and voltage of the facilities.[48]
- The cost of attachment facilities, and the incremental "but for" cost of network upgrades, are the responsibility of the generator.
- Generators are responsible for the cost of studies.
- Generation that is interconnected for capacity sales receives a defined "Capacity Interconnection Right," which is transferable.
- A generator paying for transmission upgrades receives associated incremental Financial Transmission Rights (FTRs).

<u>*Major Differences for New York*</u>*:*

- *NYISO default cost allocation to transmission owners is benefit-based, not based on load ratio share.*
- *"Capacity Interconnection Rights" are not applicable in New York.*

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48 Generally, all costs of 500kV facilities and half the costs of 230 kV and 345kV facilities are shared among the transmission owners.

- *Financial Transmission Rights associated with transmission upgrades are not applicable in New York.*

<u>*Major Differences for New England:*</u>

- *ISO-NE uses different default allocation rules.*
- *ISO-NE has different cost assignment rules under certain grandfathered interconnection agreements.*

Stakeholder-identified Sub-issues Pertaining to Cost Allocation/Property Rights

- See Appendix A-6.

Task Two: Determine "Best Practices" of Each ISO

Complete: Six Months after the Starting Point[49]

- Identify and agree on best practices that enhance the PJM platform and address critical market, reliability and market power issues

Task Three: Develop Implementation Details Regarding Regional Planning

Complete: Three Months after Task Two

- Develop regional planning rules based on existing aspects of the PJM platform, modified as necessary to accommodate best practices
- Stakeholder review of draft rules and revise as appropriate in response to such review (iterative process)

Task Four: Develop Transition Plan Regarding Regional Planning

Complete: Three Months after Task Three

- Address issues involved in combining regional transmission planning processes, generation interconnection procedures, and cost allocation / property rights rules.
- Develop transition schedule

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[49] Starting point is the Commission order in this proceeding and implementation of effective post-mediation process.

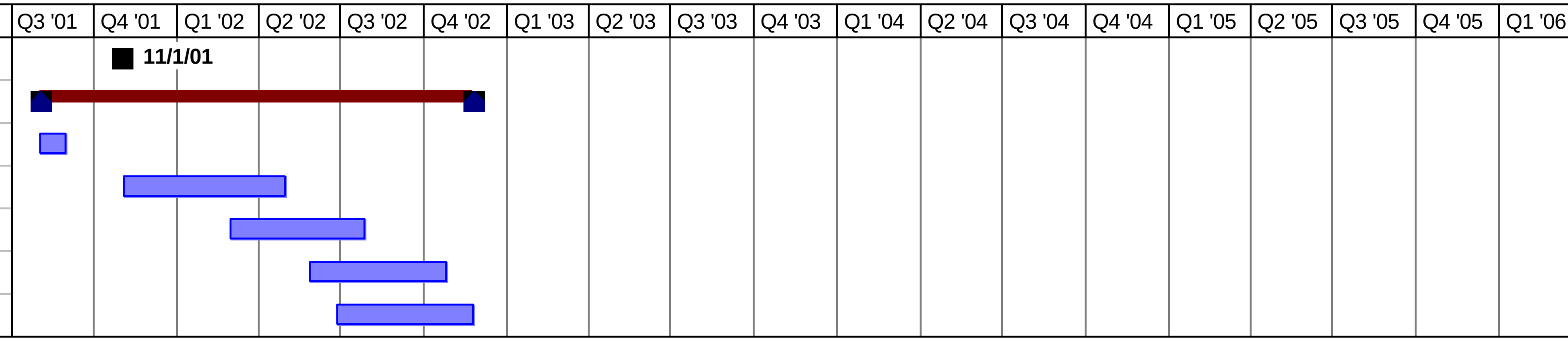
Task Five: **Finalize Tariff and other Necessary Documents Regarding Regional Planning**

Complete: **One Month after Task Four**

- Draft tariff provisions and any other necessary documentation
- Stakeholder review of tariff provisions and other necessary documentation and revise as appropriate in response to such review (iterative process)
- File with FERC

Northeast RTO Milestones for Transmission Planning and Interconnection

ID	Task Name
1	**Commission Issues Order on ALJ's Report**
2	**Transmission Planning and Interconnection (All Options)**
3	Describe Platform and Differences
4	Determine "Best Practices"
5	Develop Implementation Details
6	Develop Transition Plan
7	Finalize Tariff and Other Documents



<u>SECTION EIGHT</u>

RTO Interregional Coordination

Task One: Identify the Practices of PJM and the Other ISOs in the Area of Interregional Coordination

Complete: Done

These practices include:

- PJM has interconnection agreements with its neighboring Control Areas.
- PJM has initiated rate discussions with Alliance and the Midwest ISO as directed by the Commission.
- PJM has formed working groups with Alliance on operations and planning and soon will form a working group with Alliance on markets. PJM expects to engage in similar coordination with GridSouth.
- PJM participates in the RTO interregional collaborative process with Alliance, the Midwest ISO, Southwest Power Pool, and GridSouth. PJM also participates in the "one-stop shopping" task force with the other developing RTOs.
- PJM participates in numerous interregional planning studies including "MEN" (MAAC, ECAR, NPCC) and "VEM" (VACAR, ECAR, MAAC).
- PJM staff participate in and chair a number of NERC working groups, including those on electronic scheduling and security coordinators.

<u>*Major Differences in New York*</u>:

- *New York actively participates in NPCC, which coordinates reliability practices of five control areas, three of which are in Canada. (NYISO, ISO-NE, IMO of Ontario, Hydro-Quebec and the Maritimes).*
- *New York coordinates seasonal and other ad-hoc inter-area system studies through the Operating Studies Task Force, which has active participation from PJM and other NPCC control areas.*
- *New York has implemented special protection systems which provides for increased import capability into the Northeast US markets.*
- *New York and the IMO have continued to address potential seams issues to prepare for the opening of the Ontario market.*
- *New York, together with ISO-NE and the IMO, commissioned a feasibility analysis for a Regional Day-Ahead Market.*

<u>*Major Differences in New England:*</u>

- *ISO New England has formed working groups with its neighboring Control Areas to address operational, planning, market, communications and IT issues.*
- *ISO New England participates in numerous interregional planning studies including MEN.*

- *ISO New England staff participate in a number of NERC, NPCC and EPRI working groups. ISO New England staff also chair a number of NPCC and EPRI working groups.*

Stakeholder-identified Sub-issues Pertaining to Interregional Coordination

- See Appendix A-7

Task Two: Discuss and Review Interregional Coordination with Neighboring Control Areas

Complete: Continue existing efforts

- Involve neighboring control areas and regions early in the process and throughout the process to highlight interregional coordination aspects of issues including reliability, system operations, market operations, business practices and transmission rates.
- Issues to be addressed include, for example:
  - Participation in interconnection-wide processes
  - Means of addressing external seams
  - Relationships with Canadian regional entities

Task Three: Finalize Agreements with Neighboring Control Areas

Complete: Three months prior to Implementation of RTO for the Northeast

Northeast RTO Milestones for Interregional Coordination

ID	Task Name
1	**Commission Issues Order on ALJ's Report**
2	**Interregional Coordination (Option 1-M)**
3	Discuss and Review Interregional Coordination
4	Finalize Agreements with Neighboring Control Areas
5	**Interregional Coordination (Option 2-M)**
6	Discuss and Review Interregional Coordination
7	Finalize Agreements with Neighboring Control Areas
8	**Interregional Coordination (Option 3-M)**
9	Discuss and Review Interregional Coordination
10	Finalize Agreements with Neighboring Control Areas